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Carbon capture and storage readiness

Science Report – SC070049

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Executive summary

Carbon capture and storage (CCS) is a technology that is expected to provide CO_2 emission reductions while maintaining the security of energy supply as it allows the burning of abundant but carbon-intensive coal. CCS is believed to be of particular relevance in the context of climate change mitigation in developing countries. The technology is currently not commercially viable for a number of reasons, including uncertainty about full-scale implementation. The UK and the EU are currently promoting CCS demonstration projects and are working on the legal framework to facilitate CCS.

In light of these developments the Environment Agency aims to understand CCS, both in order to affect the national and international policy debate and to prepare and discharge any regulatory role the Environment Agency would have for CCS. As CCS is not commercially viable yet, the Environment Agency is focusing on the 'carbon capture ready' aspects of CCS, further referred to as CCR. The main objective of this project is to develop conclusions on the current political, legal, technical and economic feasibility of CCR for new power plant in England and Wales. The research undertaken under this project by Entec and Imperial Consultants around these areas was guided by critical questions from the Environment Agency at the time of writing, included in Annex V. Key conclusions of the study include:

Development of CCS. The economics of CCS itself without enhanced oil recovery (EOR) and utilisation of former hydrocarbon assets suggests that the carbon price signal for the EU Emissions Trading Scheme (ETS) Phase II and the lower range projections for Phase III are insufficient to provide incentives for CCS deployment. Sustained high oil prices combined with the expected carbon signal may generate some CCS with EOR after the demonstration projects prove general project viability. With regards to CO_2 transport networks, if total volumes of CO_2 are well understood and the legal framework permits it, least-cost network development will maximise use of hubs and trunks (mains) subject to environmental and safety constraints.

Business case for CCS readiness. There appears to be a realistic business case for power plants in the UK, sited in locations with practicable access to offshore storage, to be made capture ready. This is because capture readiness minimises the risk of the plant becoming a stranded asset if carbon prices increase. Despite the favourable business case of CCR, clear CCR regulation would ensure that operators consider properly all the minimum standards and would allow for consistency and avoidance of technology lock-in.

Relevance of regulation for CCS readiness. It is recommended that a formal requirement for plants to be capture ready is included in any future Section 36 plant permits for coal-fired stations. It is also recommended that the Environment Agency engage in the specification and verification of capture readiness, to ensure appropriate quality standards across the industry, to help engage and inform government efforts in CCS and CCR at a time of significant development, and to provide public reassurance that CCS is actually a future option for these plants. CCR is likely to be required under potential revisions to the IPPC Directive as indicated in the CCS Directive proposal.

CCS readiness. The basic requirements are that space for both the large units of capture equipment and the many smaller ancillary items and interconnections with the original plant should be provided, and that a conceptual retrofit study be undertaken to verify feasibility. In addition, the steam cycle should be capable of providing a range of possible extraction flows for solvent regeneration in a reasonably efficient manner. There must also be credible prospects that CO_2 from the site can be transported to storage. Regulators can verify such prospects by reviewing conceptual studies confirming that one or more feasible routes exist to possible storage locations and that no obstruction for CO_2 transport to exit the power plant exists.[1]

Regulatory framework for CCS. The regulatory framework for CCS itself is still very uncertain. This situation is likely to improve with the adoption of a CCS Directive expected before the end of 2009, but further legislation will be required to cover all the relevant aspects. One of the uncertain areas is that of pipeline transport, which is covered by CCR definitions in the CCS Directive proposal, but is not fully within the control of the operator. Regulation of pipeline access onshore and offshore therefore requires additional clarification. In this context, there are arguments that support the case for wider planning for CO_2 transport. The Environment Agency could consider the following issues in relation to planning:

- The role of the proposed new Infrastructure Planning Commission in relation to the provision of CCS infrastructure.
- The importance of the Marine Bill in introducing a marine spatial planning system and simplifying the marine consent regime.
- Collaboration with the Government (and the new Marine Management Organisation and relevant planning bodies) to define routes/sites for CCS infrastructure.

Recommendations

CCS is not currently commercially viable, but investment in fossil-fuel plants without CCR provisions would lead to risks of carbon lock-in. It is recommended that a formal requirement for plants to be capture ready is included in any future Section 36 plant permits for coal-fired stations. It is also recommended that the Environment Agency engage in the specification and verification of capture readiness, to ensure appropriate quality standards across the industry, to help engage and inform government efforts in CCS and CCR at a time of significant development, and to provide public reassurance that CCS is actually a future option for these plants.

In addition, the Environment Agency can support the development of CCS through support for a strong carbon price signal and facilitation of the development of a clear regulatory framework for CCS, including that of transport planning.

[1] The feasible route requirement may be more difficult to achieve for plants situated on the West coast; these difficulties could be addressed through special planning provisions.

Contents

1 Introduction

Carbon capture and storage (CCS) is increasingly viewed as an essential mitigation option if the world is to achieve the greenhouse gas stabilisation pathways that would prevent the most catastrophic impacts of climate change. CCS is seen as particularly important in international negotiations with regions of the world that rely heavily on coal for economic development such as China and India. However, the full CCS chain is not yet deployed anywhere in the world.

The concept of carbon capture readiness (CCR) – that is ensuring that new power plants are designed with the ability for CCS to be fitted at some future point – has been introduced in the recent EC CCS proposals (BERR 2007a, EC 2008a, 2008b) and the UK demonstration project competition.

The Environment Agency aims at understanding CCR both:

- in order to affect the national and international policy debate;
- to prepare and discharge any regulatory role the Environment Agency would have for CCR and eventually CCS.

The main objective of this project is to develop conclusions on the current political, legal, technical and economic feasibility of carbon capture and storage readiness for new power plant in England and Wales. The primary target audience for this report is staff at the Environment Agency responsible for:

- influencing on climate change;
- advising government on the regulatory framework for CCS;
- making decisions on regulatory applications that may have CCR implications.

The work was undertaken between December 2007 and March 2008 with an initial technical, economic and legal analysis aiming to address a series of questions of interest to the Environment Agency, presented in Annex V. The study findings are summarised as part of this report under the following headings:

2. [Definition of] Carbon capture and storage readiness
3. Key legal issues
4. Economic considerations
5. Pathway to deployment of CCS
6. The case for central planning for CO_2 pipe networks
7. Conclusions

Annex I contains information on criteria for assessing CCR applications
Annex II presents an overview of capture –ready issues for natural gas combined cycle power plants.
Annex III focuses on the economics of hubs and mains
Annex IV discusses the interaction between potential environmental and health risks and CCS economics
Annex V presents the specific questions raised by the Environment Agency to guide the study.

2 Carbon capture and storage readiness

2.1 Capture readiness and background and principles

The context for making power plants capture ready is a situation where new power plants are not being built with carbon capture and storage (CCS) but where there is a significant possibility that CCS will need to be fitted to them in the future. In the UK new power plants being built without CCS could be either supercritical pulverised coal (PC) plants or natural gas combined cycle (NGCC) plants. Integrated gasifier combined cycle (IGCC) power plants, if built at all, will almost certainly be built with CCS since they are not competitive with pulverised coal power plants without capture.[2]

Future CO_2 emissions from all sources are of interest, but coal plants have attracted particular attention because of their long economic lifetime (30–50 years) and the higher specific emissions from coal electricity generation compared to natural gas. The total amount of CO_2 that could be captured at coal plant sites is often also larger than at NGCC sites, giving better economies of scale for CCS.

One of the current reasons why new power plants are not already being built with CCS is that the technology is unproven to the level required to build large numbers of power plants that have to work reliably and cost-effectively for decades. Other reasons are insufficient regulation and legislation on the transport and geological storage (sequestration) of CO_2.

Further reasons why plants have not yet been planned with CCS-readiness in the UK are the uncertainties of how costs might be justified[3] and when technical barriers will be overcome. These reasons, taken together with the certainty that capture technology will have progressed significantly by the time CCS is implemented, and that transport and storage possibilities will then be much better defined, mean that only initial expenditure which avoids clear impediments to CCS retrofit in the future or serious performance or cost penalties can be justified.

This lack of justification for undue expenditure is recognised in the concise statement of the same capture ready principles given in the recent EC Impact Assessment for Proposed CCS Directive (EC 2008b).

[2] There is a possibility that gasification plants, probably using petroleum coke (petcoke) as a fuel, may be built in one or more UK refineries to produce hydrogen, some electricity and process heat even if CCS is not initially included in the project. Because hydrogen is required as a product, rather than just electricity, these are not competing with supercritical PC plants, and should not be termed IGCC plants either. They are not really polygeneration plants; refinery gasifier projects would be a more accurate description since their characteristics and economic viability are relevant only if linked to a refinery. Conoco Phillips' Immingham refinery is one possible UK example http://www.conocophillips.co.uk/jet_press_office/press_releases/ICHP.htm; BP's proposed Carson DF2 project in California is another. Similar plants, gasifying residual oil from the refining process, are already relatively common.

[3] Except currently for a single 300–400 MW slipstream CCS project based on post-combustion capture with coal and with offshore storage – the UK CCS Competition (BERR 2007a).

The following two requirements have been identified as *de minimis* criteria to facilitate retrofitting of CCS to new power plants:

- *Conduct a feasibility study of how capture will be added later to the plant, in conjunction with assessment of availability of suitable storage sites and of transport facilities.*
- *Include sufficient space and access requirements in the original plant, to allow capture related equipment to be retrofitted.*

(Gibbins et al. 2006a, MIT 2007).

A capacity of 300 MWe and above has been identified in the Impact Assessment as being the relevant threshold for such a capture-ready provision[4].

2.2 Definition of carbon capture readiness (CCR)

A detailed technical definition for making a plant capture ready is difficult at present. The reasons and principles for making a power plant capture ready have been summarised in a recent IEA GHG study for the G8 (IEA GHG 2007) as:

> *A CO_2 capture ready power plant is a plant which can include CO_2 capture when the necessary regulatory or economic drivers are in place. The aim of building plants that are capture ready is to reduce the risk of stranded assets and 'carbon lock-in'.*
>
> *Developers of capture ready plants should take responsibility for ensuring that all known factors in their control that would prevent installation and operation of CO_2 capture have been identified and eliminated.*

This might include:

- a study of options for CO_2 capture retrofit and potential pre-investments;
- inclusion of sufficient space and access for the additional facilities that would be required;
- identification of reasonable route(s) to storage of CO_2.

Competent authorities involved in permitting power plants should be provided with sufficient information to be able to judge whether the developer has met these criteria.

2.3 Factors affecting the need for CCR regulation and reasonable regulatory requirements

This section looks at what factors may affect the need for regulation and regulatory requirements and whether mandating CCR would be necessary.

2.3.1 The business case for capture readiness

When the costs for making a plant capture ready are low it would appear that there is a strong business case for a plant developer to make it capture ready. The justification is that it reduces the risk of the plant becoming a stranded asset if carbon prices increase

[4] EC 2008b, page 47.

in the future. It is also likely to help with permitting. If costs are higher (e.g. due to the nature of the site) and if the plant owner also feels that he or she may not be exposed to the true cost of carbon (e.g. because of the possibility of passing such costs through to customers; EC 2008a) then the business case for capture readiness will be reduced and regulation may be required to achieve the optimum outcome for society. The minimum capture-ready requirements for PC plants with post-combustion capture are also essentially the same as the maximum requirements at present, since, as discussed, no pre-investments in additional equipment are justified given the scope for future improvements. For a review of the economics of CCS, see Section 4 below.

2.3.2 Factors affecting the need for CCR regulation

A formal requirement for all new fossil-fuel power plants to have the ability to capture CO_2 in the future could be an important precursor for any subsequent legislation that would explicitly or implicitly require CCS to be implemented on plants built after a certain date as a condition of continued operation. Given that some NGCC power plants (Uskmouth, Drakelow, Barking) have already been issued with Section 36 permits that specify capture readiness, its omission from any subsequent permit could be taken as grounds for there having been a conscious decision by the regulators to exempt the plants concerned from future requirements to capture and store CO_2. It is also recommended that the Environment Agency engage in the specification and verification of capture readiness, to ensure appropriate quality standards across the industry, to help engage and inform government efforts in CCS and CCR at a time of significant development, and to provide public reassurance that CCS is actually a future option for these plants.

A formal requirement for plants to be capture ready could, however, leave all further details to the project developer. But reasons why this might not be desirable include:

- Public concern; the public interest – the need for the plant actually to be capture ready, since society as a whole may be more disadvantaged than the plant owner if CCS is not possible in the future (see EC 2008a for further discussion on this).
- The current novelty of CCS technology may mean that some project developers would be unable or unwilling to take ‘rational’ steps to make their plants CCS ready without some regulatory input to direct attention to the issues.
- There may be benefits in establishing a perceived ‘level playing field’ for utilities in the UK who are claiming their plants are capture ready.
- Setting a precedent for CCR regulation could be important. Even if current plant proposals would be made satisfactorily capture ready without any regulatory input this may not always be the case in the future. This divergence of interests could perhaps arise from technology developments or from a need to site plants in suboptimal locations for CO_2 transport and storage as the better sites get used up.
- Getting institutions ready for CCS in a variety of ways is important, and capture-ready activities are an important opportunity to do this before CCS itself happens. Engagement between the Environment Agency and industry through regulation activities is likely to lead to better implementation of CCS in various aspects of government policies. The forthcoming Marine Bill and the inclusion of offshore CO_2 capture and storage in marine spatial planning activities is one possible example.

- The development in the UK of practical regulatory approaches for capture readiness is likely to inform and influence EU legislation, which will directly affect the UK, and also possible steps to introduce capture readiness in key economies for climate change mitigation such as China, India and the USA.

2.3.3 Reasonable regulatory requirements

Capture ready requirements for the plant site

A further reason why CCR regulation might be implemented is that the costs of doing so, for both the industry and the regulator, could be regarded as reasonable when compared to the benefits. Aside from the direct benefits to the industrial developer of having a capture-ready plant, the public reassurance that might be achieved through the existence of a transparent and fit-for-purpose CCR regulatory regime could be of significant value for UK utilities.

Detailed requirements for making new pulverised coal plants capture ready for post-combustion capture were specified in the IEA GHG (2007) report on capture readiness. These were drawn up through consultation between representatives from the utility industry, equipment manufacturers and academia and subsequently subjected to peer review.

It is also worth noting that post-combustion capture for coal is currently predicted to have a similar performance to IGCC or oxyfuel on coal. There is therefore no compromise required on the basic choice of technology, especially when it is considered that post-combustion capture readiness almost certainly gives the greatest scope to incorporate future advances in capture technology. Post-combustion capture is also predicted to give the lowest costs for NGCC plants, as shown in Figure 1.

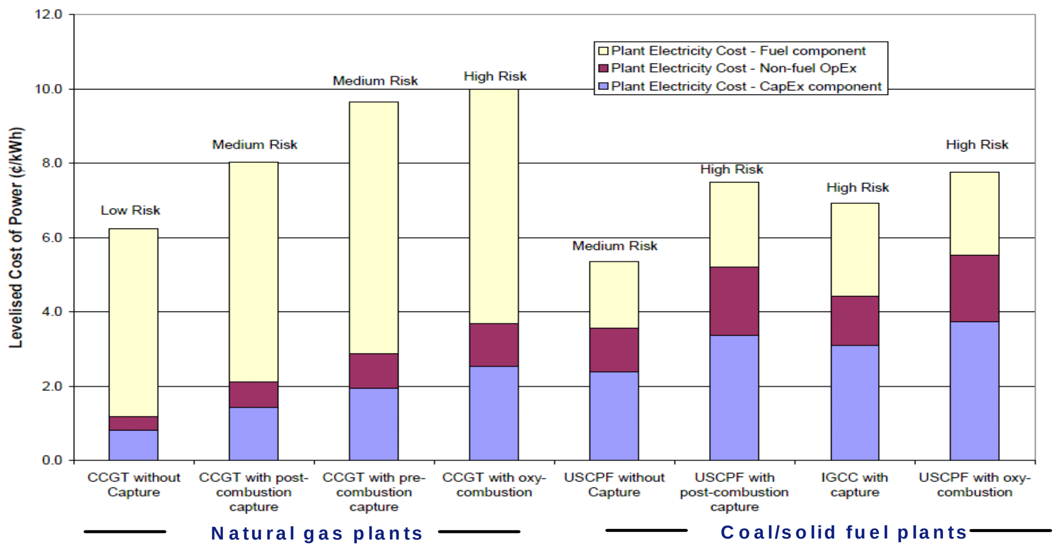

Figure 1 Illustrative comparative electricity costs for different power plant options with CO_2 capture (IEA GHG 2006)[5]

[5] Absolute values should be treated with caution but trends are consistent with other studies (Wheeldon et al. 2006, NETL 2007).

The only addition required to the list of basic CCR requirements given in the IEA GHG report to establish a regulatory approach are mechanisms to ensure and verify compliance. It is suggested that the following general approach is adopted:

(a) Clear undertakings are agreed before permitting.

(b) Where possible, relevant aspects of plant design, layout etc. and a study of CO_2 storage options are presented and approved before a final plant investment decision is made.

(c) The necessary features of the plant are inspected and approved as meeting agreed requirements at appropriate times during detailed plant design and construction.

Annex I provides further details on suggested CCR application requirements.

Requirements for transport and storage

At present it would appear reasonable for the plant proposer to show that no known obstacles exist that would prevent CO_2 transport and storage from the site. This could be done by describing one or more technically feasible schemes for transport and storage that did not entail excessive costs. The range of potential storage opportunities in the North Sea makes it unnecessary to identify individual storage sites within prospective areas. Pipeline access to offshore storage areas may, however, be more limiting, particularly close to the coast where many other activities are taking place. Pipeline routing onshore would obviously also be limiting. This is an area where government strategic planning may be required.

At a power plant site level, the Environment Agency can advise BERR and the Secretary of State on the conditions attached to granting Section 36 approval. The Environment Agency might also make capture readiness part of best available techniques (BAT) for new pulverised coal plants under regulations implementing a revised IPPC Directive, as discussed in the following section..

With regards to transport and storage, at present there is a lack of information on regulatory requirements for CO_2 transport and storage and on the prospects for CO_2 storage on the UK continental shelf. It is also likely that future players in CO_2 transport and storage (e.g. oil and gas sector companies) will only emerge once the commercial basis for a market in this area exists. It is therefore recommended that regulators require conceptual studies to verify that one or more feasible routes exist to possible storage locations. Pipeline access onshore and offshore remains a concern, but many aspects of this are beyond the control of the plant proposer and should be covered by marine spatial planning aspects of the Marine Bill. It is recommended that the Environment Agency investigates whether any measures are needed in this Bill to ensure that viable offshore CO_2 transport and storage options are maintained.

In conclusion:

- One of the current reasons why new power plants are not already being built with CCS is that the technology is unproven. Other reasons are insufficient regulation and legislation on the transport and geological storage (sequestration) of CO_2 and uncertainties of how costs might be justified[6] and when technical barriers will be overcome.
- Overall, there is a strong business case for a plant developer to make the plant capture ready. The justification is that it reduces the risk of the plant

[6] Except currently for a single 300–400 MW slipstream CCS project based on post-combustion capture with coal and with offshore storage – the UK CCS Competition (BERR, 2007).

becoming a stranded asset if carbon prices increase in the future. Where a plant is sited, and hence subsequent CO_2 transport storage costs, is an area where significant additional initial costs could be incurred. In the UK, coastal sites with access to the North Sea can probably be expected to have reasonable prospects for future transport and storage.

- It is recommended that a formal requirement for plants to be capture ready is included in any future Section 36 plant permits since, based on precedents already in place, its omission now might be construed in the future as exempting that particular plant from the need to implement CCS.

- The basic requirements for CCR are that space for both the large units of capture equipment and the many smaller ancillary items and interconnections with the original plant should be provided, and that a conceptual retrofit study be undertaken to verify feasibility. In addition, the steam cycle should be capable of providing a range of possible extraction flows for solvent regeneration in a reasonably efficient manner. There must also be credible prospects that CO_2 from the site can be transported to storage. Regulators can verify such prospects by reviewing conceptual studies confirming that one or more feasible routes exist to possible storage locations and that no obstruction for CO_2 transport to exit the power plant exists; see more on these aspects in the section on planning below.

3 Key legal issues

3.1 The legal position on carbon capture readiness

This section reviews the existing legal framework for CCR in the UK and EC and proposed changes. It focuses on the capture readiness of power plants, and in particular where the Environment Agency may or may not have powers to require CCR. Options for transport and storage are also covered in Section 5. This is because other agencies are involved in the latter area and also because minimal or no actions by project developers are likely to be necessary beyond the power plant site boundaries to allow CO_2 transport and storage from proposed new coastal coal power plant sites.[7]

Given the novelty of the subject, there are few explicit provisions for carbon capture in existing legislation. As outlined below, there is new or amended legislation on the horizon, but this section also reviews the potential use of existing legislation to justify a capture-ready requirement.

3.1.1 EU legislation and policy direction

In recognition of the regulatory gap surrounding CCS, on the 23 January 2008 the EC adopted a proposal for a CCS Directive (EC 2008b), which sets out the intended regulatory framework. The two main provisions relating to capture are:

- A conclusion that the IPPC Directive provides the appropriate regulatory framework for CO_2 capture[8] and an associated amendment to the IPPC Directive to cover capture.[9]
- An amendment to the Large Combustion Plant (LCP) Directive[10] to require operators of new plant built after the Directive comes into force to fulfil *de minimis* criteria[11] that would facilitate application of CO_2 capture technologies at a later stage.

It should be noted the proposal is to integrate the LCP Directive in the next revision of the IPPC Directive.

The co-decision process of formalising this proposal will be lengthy and, although it will resolve many of the challenges relating to CCS, there will be a gap in the interim period. In order to regulate CCS during this interim period, UK legislation is more directly relevant.

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[7] There is a need to ensure that other users of the sea and seabed offshore from the power plant sites do not preclude CO_2 pipeline routes by earlier activities, with offshore wind farms being a potential new concern. This is an area that should be covered by the marine spatial planning aspects of the proposed Marine Bill but CO_2 transport and storage appears to be omitted from the list of 'all human activities' in current studies (MSPP Consortium, 2006; http://www.abpmer.net/mspp/).
[8] EC (2008a), Recital 12.
[9] EC (2008a), Art 30.
[10] EC (2008a), Art 32.
[11] Namely to have suitable space for capture technologies and to assess the feasibility of CCS.

3.1.2 UK legislation

According to explanatory notes by BERR on the Energy Bill (2007–08)[12] most of the activities involved in CCS are standard industrial processes and can be readily regulated by established legislation. However, permanent storage of CO_2 is a new concept, and existing legislation to control depositions below the surface of the land and seabed is not well suited to licensing the storage of CO_2. The Energy Bill (2007–08) establishes a framework for the licensing of CO_2 storage and the enforcement of the licence provisions. It also applies existing offshore legislation (e.g. the decommissioning legislation in the Petroleum Act 1998) to offshore structures used for the purposes of CO_2 storage.

The main pieces of UK legislation relating to the regulation of capture readiness are the Pollution Prevention and Control Act 1999 (PPC[13] – the UK implementation of IPPC Directive) – now the Environmental Permitting Regulations (EPR) 2007 and the Electricity Act 1989. Unsurprisingly there are no direct references to CCS or capture readiness in either of these. If the proposed EU directive is agreed as it stands, then CO_2 capture and capture-readiness regulation would need to be transposed into UK law (most likely through the PPC Act and Electricity Act respectively).

In England and Wales, the Environment Agency administers power plant applications and operations under the EPR 2007.

The development approval of new power generation plants >50 MW falls under the Electricity Act 1989, Section 36, consented by DTI (now BERR) Secretary of State. Smaller power stations are approved by the Local Planning Authority (LPA) under the normal planning regime.[14]

If the Commission's CCS Directive is adopted then the capture-readiness requirement could be transposed into UK law in the Section 36 requirements. Since the proposed EC requirement stipulates capture readiness for those plants greater than 300 MW, the possibility of smaller plants being required to be capture ready is unlikely, but is not set until the Directive is transposed into UK law. In any case, the Energy White Paper suggests that Section 36 is likely to be amended to include 'CCS readiness' requirements.

However, if the Environment Agency wanted to require capture readiness at present, on basis of a preliminary assessment it appears that there are two approaches, as outlined below.

(a) PPC and Best Available Techniques

Coverage of CCS under PPC

The PPC Regulations are concerned with the regulation of 'installations' which contain one or more listed 'activities'. For post-combustion capture as applied to pulverised coal power stations, which are the focus of this document, the 'activity' will be the power station.[15] This type of capture unit (e.g. solvent scrubbing and CO_2 compression) would not appear to be an activity in its own right as identified in Schedule 1 to the PPC Regulations.

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[12] http://www.publications.parliament.uk/pa/ld200708/ldbills/052/en/2008052en.pdf.
[13] SI 2000/1973.
[14] Task Force on UK regulation of CO_2 Capture and Storage (CCS). Working Group 3 – Capture, capture-ready and transport on-shore (July 2006).
[15] Section 1.1 Part A(1) (a) of Schedule 1 to the PPC Regulations.

The capture unit would appear to fall within the 'installation' as it is assumed that it would:

- be on the same site as the power station (the stationary technical unit);
- be directly associated with the power station, as it serves the power station;
- have a technical connection with the power station, as it would be an integral part of the overall activity;
- have an effect on pollution.

Pipelines for CO_2 transport to storage facilities would not fall within the installation where they were not on the same site and/or where they were multi-user or national pipeline systems (which would break the technical connection).[16]

Best Available Techniques (BAT)

The PPC Regulations require that 'all the appropriate preventative measures are taken against pollution, in particular through the application of the best available techniques (BAT)'. CO_2 can be regarded as a pollutant as defined within the PPC Regulations and as considered in a recent legal case,[17] although aspects related to the EU Emissions Trading Scheme (ETS) apply, see below.

BAT is used to provide the basis for emission limit values (ELVs).

The amendment to the IPPC Directive as a result of the EU ETS led to the exclusion of CO_2 ELVs. The Environment Agency considers that this exclusion also applies to other permit conditions related to CO_2. The EC Proposal for a CCS Directive suggests that the IPPC Directive can be amended to accommodate the need to regulate CCR at power stations.

Following this amendment BAT-based permit conditions could be applied for power stations for capturing CO_2.

The actual determination of BAT for a specific power station will be made by the competent authority (Environment Agency for England and Wales) taking into account the technical characteristics of the installation concerned, its geographical location and the local environmental conditions. Within the interpretation of 'available' for BAT in the Regulations, there is a requirement that techniques 'have been developed on a scale which allows implementation in the relevant industrial sector, under economically[18] and technically viable conditions'. It is unlikely that CCS itself would be approved as BAT before commercial viability is proven (e.g. through demonstration projects). However, CCR could be defined as BAT for certain types/sizes of power stations.

The Large Combustion Plant BREF (EC 2006b) stated that CO_2 capture techniques were under development but could not (at that time) be considered as BAT. The BREF did not discuss whether or not capture readiness could be considered BAT in anticipation of these techniques maturing within the operating life of a new plant.

BAT evolves with time and will take into account developments in CO_2 capture technology. Until such technology is considered to be BAT, capture readiness might potentially be considered BAT for new coal power stations (or later for existing power stations build after a certain date), assuming this was economically viable for the

[16] See EA IPPC Regulatory Guidance Series No.5 (Interpretation of 'Installation' in the PPC Regulations) for more detailed information.
[17] In a recent legal case against Veolia's Newhaven incinerator, the High Court dismissed the PPC permit as it said the Environment Agency had failed to properly assess CO_2 emissions from the plant and so the permit was unlawfully granted.
[18] EC 2006a.

sector.[19] However, there is a low probability risk that this might be disputed as capture readiness in itself is not a pollution abatement technology

(b) Requirement for Consent (Electricity Act)

A revision of Section 36 as discussed in the Energy White Paper would provide a more formal route for the Environment Agency to regulate CCR.

3.2 Current initiatives

3.2.1 Scope for indirect action on capture readiness

A number of policies are currently under development concerning CCR. At the time of writing, these are:

- Proposed CCS Directive (EU): under the proposed directive, the capture aspects of CCS would be dealt with under the IPPC and the Environmental Impact Assessment (EIA) Directives. Capture readiness would also be included in the LCP Directive.
- Proposed changes to Section 36 (UK): the Energy White Paper mentions BERR intentions to go to consultation with regards to potential changes to Section 36, specifically to require ‘CCS readiness’.
- Proposed revised IPPC Directive (EU): no mention of CCS is included in the proposal for the revised IPPC Directive. However, the proposed CCS Directive amends the IPPC Directive to cover CO_2 capture.
- Energy Bill (UK): this mentions CO_2 storage but not capture or ‘CCS readiness’.

It is recommended that the Environment Agency keep up to date with the developments of these initiatives.

3.3 Onshore storage

3.3.1 Location of potential onshore storage

As shown on the map in Figure 2, there is far less onshore storage capacity in the UK than offshore. Despite this, onshore storage remains of interest, particularly in proximity to existing or potential large emitters. However, onshore storage is not being considered in BERR’s CCS demonstration competition and commercialisation is expected later than offshore storage.

[19] For example, as determined through application of EC 2006a.

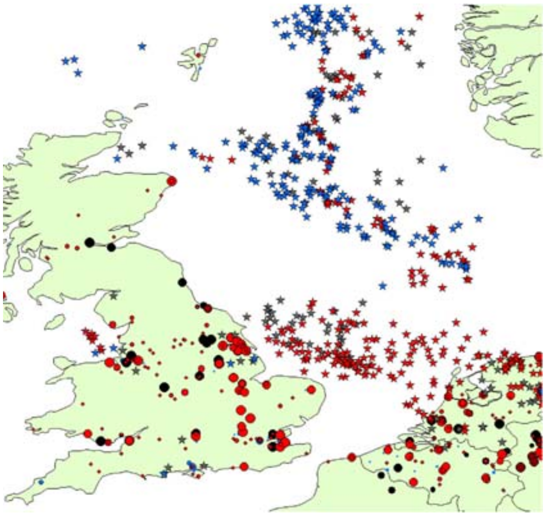

Figure 2 UK fossil-fuelled power plants (circles) and potential CO_2 storage sites (stars)

For power stations red denotes gas, blue denotes oil, black denotes coal. For storage sites blue stars denote oil field, red stars denote gas field, grey stars denote aquifers.
Note: the figure also shows some Danish, Dutch and Norwegian storage sites (Kjärstad and Johnsson 2007).

3.3.2 Technical aspects

The use of onshore depleted fossil-fuel fields and salt caverns for temporary storage of natural gas, which uses comparable technologies to CO_2 storage, is a mature process with sites across Europe. Similarly, injecting CO_2 into onshore oil reserves has been undertaken for a number of years for the purpose of enhanced oil recovery (EOR).

Furthermore there are a number of demonstration projects worldwide being used to study onshore CO_2 storage in different structures, including:

- former gas storage salt mines: CO_2SINK, Germany;
- depleted natural gas fields: in Salah, Algeria, and CASTOR, Austria;
- saline aquifer: Frio, USA;
- coal seam: RECOPO, Poland.

The implication is that the technologies required for onshore storage are available.

3.3.3 Costs

In addition to reduced costs associated with shorter transport distances, the infrastructure and operating costs associated with onshore storage are lower than for offshore storage. It has been estimated that costs in the Netherlands are 2 €/t CO_2 (Hendriks et al. 2003). However, CO_2 injection well costs increase exponentially with depth; the difference between injection to an aquifer at 800 metres depth and a 4,000-metre-deep depleted gas field could differ by a factor of between 5 and 10 (OECD/IEA 2004).

3.3.4 Legislation

The Energy Bill (2007–08) framework is limited to the offshore area only. This is due to the fact that this area is likely to be of primary interest to developers in the short term. Moreover, storage of CO_2 onshore requires amendment of existing EU Directives. While such amendment forms part of the Commission's proposal for a Directive on the geological storage of carbon dioxide presented in January 2008 covering onshore and offshore storage, the details of any Directive finally adopted will be a matter for agreement within the EU Council and the European Parliament.

When current legislation was drawn up CCS was not envisaged. Consequently, a number of EU-driven Regulations apply to onshore storage including:

- Waste Framework Directive;
- Landfill Directive;
- Integrated Pollution Prevention and Control Directive;
- Groundwater Directive;
- Water Framework Directive;
- SEVESO II Directive.

The main potential barrier is that CO_2 for storage is classified as a waste. There is uncertainty whether this definition is avoided if the CO_2 is used for EOR. There are also conflicting opinions on whether the Waste Framework Directive prohibits the onshore storage of CO_2. This uncertainty should be resolved by revisions to the EU Waste Directives and Water Framework Directive proposed by the CCS Directive to enable CO_2 storage.

3.3.5 Planning

The activities of site selection, environmental impact assessment, construction, operation, closure, monitoring and remediation are similar to those for onshore gas storage and oil extraction, which are covered by subsurface legislation within the Petroleum Act. Also the Gas Act, by way of a Storage Authorisation Order, applies to onshore underground gas storage by a licensed gas transporter. These could be used to inform guidance on CO_2 storage planning assessments.

Currently, applications for onshore gas, or potentially CO_2, storage must obtain permission via the Town and Country planning system through local authority planning departments, who may have minimal competence in such projects. Recently BERR overruled a Yorkshire council local planning refusal for an onshore gas storage project (Planning Portal 2008) and reforms have been proposed by the Planning White Paper for applications for projects of national significance to be assessed at a national rather than local level.

3.3.6 Health and safety

A report by the Health and Safety Executive (HSE 2006) concludes that existing health and safety regulatory systems are on the whole suitable for energy developments in the Energy White Paper, including onshore gas storage and CCS.

Key issues highlighted for further investigation, with respect to CCS, are:

- Properties and behaviour of supercritical or dense phase CO_2 particularly following a leak.
- Standards and codes of practice for dense phase CO_2 plant and equipment to ensure a consistent approach to safety-related engineering issues.
- Whether the large-scale presence of CO_2 should trigger any of the major hazard legislation.
- Regulatory issues related to long-term responsibility for storage sites once injection has been completed.

The proposed CCS Directive also identifies the need to assign responsibility of sites, via permitting, to ensuring storage minimises environmental and human health risks.

3.3.7 Long term liability

The Energy Bill (2007–08) framework is limited to the offshore area only**.** A big uncertainty with respect to onshore CO_2 storage is who would retain long-term ownership of a storage site. Current PPC Regulation would only regulate the site until injection activity ceases. Currently, there are no guidelines regarding monitoring, regulation or liability following decommissioning. Discussion at a technical working group of the London Convention in April 2006 seemed to suggest that there was no alternative to the state taking on long-term liability, ownership and monitoring of CO_2 storage sites. Details would need to be developed and formalised before an operator could be expected to invest in a scheme.

The EC Proposal for a CCS Directive mentions methods of regulating long-term liability, and a regulation to detail the legal framework further will be under development starting from the summer of 2008.

4 Economic considerations

4.1 Costs of CCR

The costs of CCR are set out in more detail in Annex 1. The analysis showed that the cost of securing additional land required for CCR is limited compared to the overall investment costs needed to build a plant (without CCR). The land required is estimated to be approximately 9,500 m^2, taking into consideration that sufficient space and access is required in the original plant, to allow capture-related equipment to be retrofitted.

The cost of CCR will depend on the size of the plant, the location and type of land available near the plant. For example, the EU estimates of land costs vary from £2(€2.50)/m^2 for bare soil, to £14(€20)/m^2 for outside city area, to £24(€35)/m^2 for city area. Overall costs are estimated in the region of £14,000–173,000 for a 400 MW plant and £16,000–226,000 for a 500 MW plant. This represents 0.003 to 0.04% of the capital cost (assuming the cost of a power plant without CCR is £1,017/kW).

A large proportion of new power stations are erected in the place of decommissioned plants (brownfield developments). Of the approximately 25 new power stations >300 MW in the UK that could potentially be commissioned over the next five years, based on current public domain information, at least one-third would be erected in place of decommissioned plants and a further third built as extensions or adjacent to existing power stations. Most of the remaining plants are planned for other brownfield sites. In almost all cases there is vacant land in the immediate vicinity of the site, which could potentially be used to expand the size of the site to accommodate carbon capture. However, this would be subject to a number of factors, including suitability, planning consent, availability and cost.

The direct, obvious financial impact of other *de minimis* CCR requirements, such as proving that a feasibility study has been undertaken and an adequate transport route and storage have been identified, is likely to be very limited and to be expressed in terms of cost of staff time.

An exception to this could be if the requirements are translated into the need to change the location of a plant in order to ensure access to transport and storage, since this would entail significant costs.

4.2 Costs of CCS

In the context of this study, the most relevant way of measuring the costs of CO_2 capture, transport and storage is in terms of £/t CO_2 abated.[20] Costs per unit of CO_2 abated include costs of capture and initial compression, transport and compression during transport, and storage.

[20] Other methods of measuring CCS costs include added costs per unit of electricity produced, capital costs, variable costs etc. Additional information on these can be found in IEA (2006/8), IPCC (2005) and Poyry (2007) among other sources.

The costs of **capture** vary from technology to technology; there is a significant difference between the costs related to coal and gas-fired generation, see Figure 3:[21]

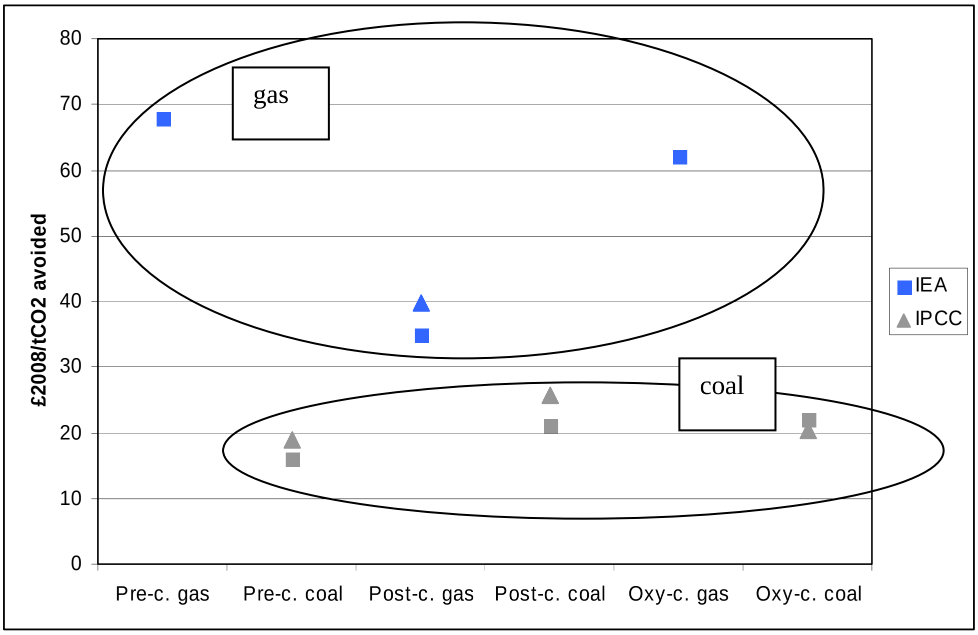

Figure 3 Cost estimates of CO_2 capture

Source: Entec on basis of IEA (2006) and IPCC (2005)[22]; c.= combustion; triangles refer to IPCC and squares to IEA; blue refers to gas and grey to coal.

While CO_2 can be transported by truck and ship, pipelines are widely considered the most technically and economically feasible option.[23] Given the nature of **pipeline transport**, costs depend on the distance to be covered, but also on the size of the pipeline. Therefore a larger CO_2 source or a source that can combine transport efforts with other adjacent sources will incur lower costs per unit than a small single source (the economics of hubs and mains are discussed in Annex III). It is obvious that cost estimates are project and context specific:

[21] The cost is calculated in reference to a baseline plant (assumed to be of the same type and design) and is calculated by comparing the cost and emissions of a plant with capture and those of a baseline plant without capture.

[22] All cost estimates are transformed from the nominal value of the original currency into GBP (exchange rates for the year derived by averaging daily rates from US Federal Reserve Statistical Release (2008) and European Central Bank (2008)) and inflated to £2008 by applying UK's CPI from UK Office of National Statistics (2008)).

[23] In some applications, ship transport can be more economical than pipeline transport.

Table 1 Estimates of unit cost of pipeline transport

Unit cost estimates (£$_{2008}$/CO_2)	
Study	**Estimate**
IEA GHG (2005b)	0.8–2.3/tCO_2/250 km
EC (2008b) (note: transport and storage)	4–15/tCO_2
Poyry (2007) (estimate for a single project, assumes scale of 400 MW with capture coal-fired station[24])	Onshore (small diameter): £4.5/tCO_2 abated Offshore (large diameter): £0.3/tCO_2 abated
Sources: IEA GHG (2005b), Poyry (2007)[25], EC IA (2008)	

Estimates of unit costs of **storing CO_2** are typically lower than estimates for capture and transport. The technical cost of storage is generally expected to be lower onshore than offshore, although this conclusion does not include an assessment of monetised risks to human health and to the environment. Both onshore and offshore storage options can be classified into saline formations/aquifers,[26] depleted or disused gas and oil fields, and existing oil and gas fields for enhanced oil recovery (EOR). The charts in Figure 4 summarise cost ranges for the different type of storage produced by the IPCC and IEA, with the exception of EOR:

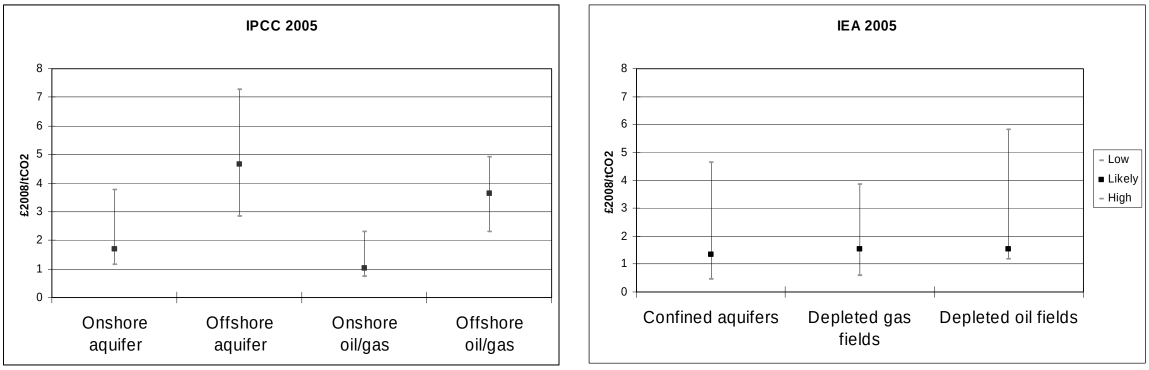

Figure 4 Cost estimates of CO_2 storage

The UK is well endowed with storage potential, particularly in the North Sea. While unit costs of storage are expected to increase after the least-cost options are used, the storage potential of the EU in general and the UK in particular is high. This means that there is a considerable low-cost storage potential: the EC Impact Assessment of the CCS Directive (EC 2008b) is based on the assumption that up to

[24] The costs for this case study are higher than is generally expected for post-demonstration projects since the plant size considered is about two times lower than the 800 MW capacity expected for new generation coal-fired stations.
[25] See Annex I for assumptions in the Poyry and IEA reports.
[26] Currently there is 'greater geological uncertainty over the potential to store CO_2 in saline aquifers. To date they have not been well characterised geologically because of their limited economic value' (BERR, 2007).

approximately 30 Gt CO_2 (or over 7 times the EU27 CO_2 emissions in 2005) can be stored in Europe at a cost below £5.6/t (€8).[27]

In summary, the minimum estimates of the IEA, IPCC and Poyry studies considered above add up to £17.3/t CO_2 captured, transported and stored. This is very close to the EC (2008b) estimate of £17/CO_2 (€25). The upper range of the estimates differs considerably, as shown in Figure 5.

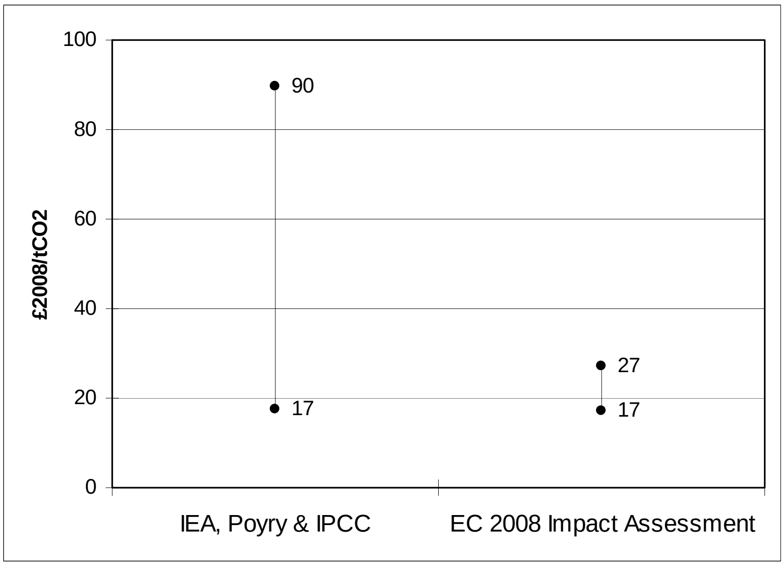

Figure 5 Summary CCS cost estimates (capture, transport and storage)

The divergence in maximum costs may be caused by the wider range of options considered in the IEA, Poyry and IPCC reports. Also, note that minimum estimates differ from 'most likely' estimates.

The main sources of uncertainty for the estimates above include:

- Lack of commercial size integrated project experience. The estimates for all the costs are separate and the costs of running a real capture to storage project are unknown.
- For capture, it is possible that the cost estimates above are under-estimates. Over 2007, the price of power station equipment has increased considerably: for example Platts report an increase by 36% in the cost of a new build supercritical pulverised plant from €1,100/kW to €1,500/kW (Platts News Feature 2007). The CO_2 capture equipment is likely to be affected in a similar way.
- Pipeline costs are closely related to the price of steel, which undergoes cyclical fluctuations caused by world demand and supply, but is also affected by the cost of energy sources such as coal, gas and electricity.
- Overall project costs are highly dependent on the cost of financing (e.g. cost estimates in Element Energy et al. (2007) suggest that the cost of pipeline financing is equivalent to the cost of the project itself, i.e. financing doubles the initial cost estimate). The studies reviewed use different financing costs and discount rates, see Annex III. This should be taken into account for a detailed review of costs. Financing costs depend on the

[27] Note that the estimates for transport and storage do not include the enhanced oil recovery (EOR) option or the option of re-using existing gas pipelines in reverse.

general economic situation, but also on the regulatory framework and the risk profile of the investment. Risk premiums that would be applied now for CCS are expected to decrease with time. The EC modelling used around 5% in 2020 (after the planned demonstration projects are under way), decreasing to around 1% in 2030 for all technologies with the exception of oxyfuel generation, the risk premium for which is expected to stay at a higher level until 2030 (see Annex III for assumptions on discount rates in the CCS cost studies reviewed).

- Fluctuations in fuel costs will affect the overall cost of capture, transport and storage (and added cost per unit of electricity produced). This is due to the energy penalty of capture and compression.

In the short run, CCS costs are likely to be higher than the lower and mid estimates of the sources considered in this note as primary energy costs, steel prices and power generating equipment costs have increased since the latest assessments were made. In addition, financing costs and unexpected integrated project implementation costs are likely to be high, again, at least in the short-run. In the medium term, as uncertainty decreases, implementation and financing costs may drop off. Other costs such as energy and steel can both increase and decrease.

Some of the sources considered include (very limited) learning effects.[28] Capture technology learning curve effects are expected to be minimal, estimated at around 3% in the EC Impact Assessment[29] (i.e. 3% reduction in costs per year). Given the technology shift that can be envisaged as the commercial implementation of CCS progresses, it is possible that after the ‘first of a kind’ plants are built with the intrinsic larger costs, the costs reductions from learning would be higher than the classical 3% learning curve. Transport and storage are believed to be mature technologies with experience to be drawn from hydrocarbons development and transport and therefore no learning curve effects are expected (with the exception of monitoring costs perhaps).

Note that the assessment above includes cost elements of CCS projects independent from the oil and gas industry. However, there are potential synergies between the oil and gas industry and CCS:

- Firstly, existing gas pipeline infrastructure can be used to transport CO_2 to depleted gas fields.

- Secondly, CCS can be used for operational hydrocarbon fields for enhanced oil recovery.[30]

In both cases, the economics of CCS are enhanced.

[28] Here the definition of learning effects does not include uncertainty reduction further to commercialisation.
[29] EC (2008b)
[30] The proposed EC Directive does not preclude EOR as a CO_2 storage option.

5 Pathways to deployment of CCS

The key factors in CCS deployment are:

(i) Removal of high-risk perception through demonstration projects.

(ii) If the EU proposal for a revised Emissions Trading Scheme (ETS) – EC 2008d - is approved and CCS is allowed into the EU ETS.

(iii) A sufficiently high carbon price.

(iv) Additional promotion of CCS in the UK aimed at meeting strict domestic greenhouse gas (GHG) reduction targets either through mandatory requirements from operators, grants or other incentive mechanisms.

5.1 Removal of novelty risk

It is unlikely that CCS will be deployed on a large scale before the commercial and technical viability of CCS is proved through commercial-size demonstration projects, which are likely to start in the next few years (DTI 2007).

5.2 Level of strength of carbon price signal

Once the critical novelty concerns are removed, the deployment of CCS under current policy proposals (primarily the EU ETS mechanism) will depend on the level and strength of the carbon price signal. Early assessments suggest that the allowance to use Joint Implementation/Clean Development Mechanism (JI/CDM) during Phase II was over-generous and without any measures taken, the price for allowances is at a risk of collapsing. To relieve the situation in Phase II, it is proposed that operators are allowed to carry forward (bank) JI/CDM credits from Phase II into Phase III. Should this proposal be implemented, the price of carbon during Phase III would reach £20 (€30) per t CO_2e according to EC (2008c), rather than the £27 (€40) per t CO_2e used for the modelling of CCS viability (EC 2008b). Note that the £20 per t CO_2e price is closer to the lower range of the CCS cost estimates reviewed above and that there are good reasons to believe that the lower range of the CCS cost estimates are underestimates.

Carbon price prognoses are intrinsically uncertain as they entail assumptions about abatement costs in different sectors etc. Therefore, it is possible that the carbon price will reach levels well above those estimated by the EC modelling, e.g. analysts external to the EC are suggesting that the price may be as high as £34 (€50) – £47 (€70) per t CO_2e (Point Carbon News 2008).

In addition to the uncertainty of the carbon price analysis per se, there is considerable added political uncertainty. In particular, this is related to the 30% GHG emission reduction target set by the EU in the eventuality that an international post-Kyoto agreement is reached, compared to the 20% target in the case of unilateral action. Under the 30% target, unlimited use of JI/CDM credits will be accepted and linking with other emissions trading schemes is expected. This can cause EU carbon prices to go either up or down compared to the 20% target baseline.

The economics of CCS suggest that the carbon price signal appears to be insufficient both with regards to the level of the expected carbon price as well as with regards to the potential fluctuations around that expectation for CCS projects that would not be combined with EOR and would not use existing transport infrastructure. However, sustained high oil prices combined with the expected carbon signal may generate some actual CCS after the demonstration projects.

More certainty with regards to the effectiveness of the EU ETS mechanism will be obtained once the Phase III ETS proposals are debated in the EU Parliament and Council with eventual changes and a subsequent adoption.[31]

5.3 UK action to meet strict internal GHG reduction targets

The UK's Climate Change Bill (which is expected to receive Royal Assent at the end of 2008) will set a target for the UK to reduce CO_2 emissions by at least 60% below 1990 levels by 2050.[32] This legislation will require the Government to set five-year carbon budgets in order to ensure that the overall target is met.

In achieving these budgets, the Government will aim for the least-cost solutions. The Office of Climate Change is currently updating existing abatement cost models which will be used for setting the five-year budgets and therefore it is not possible to state with certainty at the time of writing how much of a role CCS is expected to play in reaching the UK's targets. However, recent runs of existing models, such as the McKinsey curve and modelling underpinning the 2007 Energy White Paper issued by BERR, show CCS as one of the abatement measures considered in the medium term. In the Energy White Paper 2007 it is assumed that this will happen before 2020; other research suggests that deployment is more likely during 2020–2030 (e.g. McKinsey curves presented in CBI 2007.

In particular, the McKinsey curves (CBI 2007) suggest that CCS is not expected to be commercially deployed in 2020, when the marginal abatement costs of reaching the 2020 target are likely to be around £60–£90/t CO_2e (well above the low–mid range of CCS cost estimates), but is likely to play a role between 2020 and 2030, when abatement costs are expected to decline to about £30–40/t CO_2e. In that period, CCS from coal-fired stations is expected to be deployed, and is seen in terms of abatement potential and costs between the options 'onshore wind deployment between 10% and 20%' and 'management of soil CO_2' in the merit order of major abatement options. CCS from gas-fired stations is believed to be too costly to be deployed in order to meet the UK's 2030 emission reduction target.

These preliminary assessments suggest that CCS from coal would constitute a cost-effective option for meeting the UK's targets both before and after 2020, provided that significant requirements for risk premiums are removed by the demonstration projects.

In order to provide incentives for its uptake, CCS can be made mandatory for all or selected types of fossil-fuel fired plants. This would lead to the operators bearing the costs of CCS, which are likely to be passed on to consumers depending on other generation options. Here, requirements of liberalised electricity markets would have to

[31] Under 100% auctioning to the electricity sector, the carbon price would act as an opportunity cost – without CCS, allowances would be purchased in the auction or on the market; with CCS investments, the requirement for allowances for the operator would be considerably reduced.
[32] Source: http://www.defra.gov.uk

be considered, as would whether UK operators (and potentially their consumers) are exposed to a harsher treatment than their EU counterparts.[33]

Alternatively, full/partial grants or other incentive mechanisms could be made available for CCS deployment. This would be most relevant if CCS proves to be an effort that exceeds EU ETS requirements; that is, in the case where the allowance price is not sufficiently high to bring about CCS, but CCS brings sufficient social benefits compared to other GHG abatement options such as energy efficiency and renewables. For example, Climate Change Capital (2007) recommended that a number of CCS-related risks are managed by the public sector, including contracting and interface risk related to linking into one project a power plant and a storage site (as well as a chemical plant in case of the a pre-combustion gasification process), transport, and storage licensing risk and long-term storage liability.

In both cases (the EU ETS mechanism or a potential UK policy) it is essential that investors receive a long-term signal. Should a large CCS deployment be favoured, a clear policy signal will reduce risk premiums applied by financiers and will allow for efficient transport and storage networks to develop. Both would lead to cost reductions.

Under the EU ETS mechanism it is likely that CCR will turn into CCS at the same time as when new built plants include CCS – in response to the carbon price signal. The main institutions controlling the key factor under this scenario – carbon price – are the European Parliament and the European Council through their power to influence the design of the revised Emissions Trading Directive.

Under an EU ETS policy scenario, the timing of CCR turning into CCS will depend on the specifics of the policy itself. The design and approval of the policy would be under the remit of the European Council of Ministers and Parliament and then for the UK institutions to translate any approved directives into UK law. Should IPPC BAT be used as a vehicle to promote CCS, CCR could turn into CCS as soon as this can be deemed as commercially and economically viable under BAT rules.

5.4 Value and acceptability of enhanced oil recovery (EOR)

In addition to the key factors affecting the carbon avoidance aspect of it, CCS can also be favoured for enhanced oil recovery, particularly if sustained high oil prices support it.

The acceptability of CCS for EOR is debated in the literature, given that additional fossil fuel is extracted through the storage of CO_2. Because of the large oil reserves elsewhere in the world and the enormous demand for oil, using EOR in Europe does not obviously lead to increase emissions compared to the baseline in the short to medium term. In the longer term, the climate benefits of CCS projects with EOR depend on a number of factors including whether additional oil would have been produced by some other route if CO_2 had not been used and how the reservoir is managed (for maximum oil recovery or maximum CO_2 storage). The Proposal for the Directive on CO_2 Storage (EC 2008a) does not forbid CCS for EOR.

In addition to the potential to promote CCS under IPPC, as discussed in Section 3 above, there are a number of indirect actions within the Environment Agency's remit that would assist in CCS deployment:

- Ensuring CCR, which will reduce the cost of CCS deployment and increase its scope.

[33] In the event that CCS was deemed BAT under the IPPC Directive, economic viability would need to be assessed for the EU power sector as a whole.

- Through its policy influencing role, support strict EU ETS targets in Phase III.
- Support UK policy initiatives to provide incentives for CCS over and above the EU ETS incentives.
- Support any health and environmental assessments that would increase the public's confidence in the safety of CCS.

6 The case for central planning for CO_2 networks

Planning permission is required for developments above the mean low water mark. Planning decisions are taken in accordance with the relevant development plan, unless material considerations indicate otherwise (Section 38(6) of the Planning and Compulsory Purchase Act 2004). The development plan comprises a suite of spatial planning documents:

- Regional Spatial Strategies, currently prepared by Regional Planning Bodies, which define strategic priorities for development.
- Development Plan Documents, prepared by Local Planning Authorities, which allocate or safeguard land for specific uses.

National planning policy and national policy objectives are set out in Planning Policy Statements (PPS). Spatial Plans must be consistent with national planning policy and policy objectives.

In addition to the Town and Country Planning Acts, planning permission may be granted under the Electricity Act 1989. Section 36 of this Act provides for deemed planning permission to be granted when consent for power generating stations over 50 MW is given. Planning permission for pipelines (including those for CO_2 transport) can be achieved through the Section 36 consent process, or by a separate planning application to a local authority under the Town and Country Planning Act.

There is currently no equivalent planning system applicable to development in the marine environment. Below the mean low water mark development is consented by a range of licences and statutes. These include the Food and Environment Protection Act 1985, the Coast Protection Act 1945, the Petroleum Act 1998 and the Electricity Act 1989. CO_2 storage operations (with CO_2 expected to be injected at least 1 km under the seabed for storage of CO_2 produced in the UK and transported offshore) are expected to be regulated by EU Directives and Regulations and a draft Directive on the main provisions for geological storage was published on 23 January 2008. International treaties (OSPAR and London) are also relevant and have recently been amended to allow CCS, although the ratification process is not yet complete.

6.1 Changes to the planning and marine licensing regimes

The Planning Bill, currently before parliament, proposes the following:

- A new Infrastructure Planning Commission to take decisions on major infrastructure of national importance, including energy developments.
- Decisions would be based on new National Policy Statements.
- The hearing and decision-making process by the Commission would be timetabled.

The draft Marine Bill, published April 2008, proposes:

- A single unified approach to marine planning, licensing and marine conservation.

- Regional marine plans, to be prepared within the context of a Marine Policy Statement (MPS).
- An integrated licensing regime.
- The creation of a new organisation, the Marine Management Organisation (MMO), to administer the new planning and licensing system.

The Government is considering provision in the Marine Bill for secondary legislation to regulate CCS in the marine environment.

6.2 Planning issues

The planning issues related to a CCS pipeline/storage network include:

- Compatibility with other land/marine uses (residential, employment, fishing, transport routes, marine dredging, offshore wind farms, oil and gas extraction).
- Environmental acceptability (how significant are the effects on ecology, landscape/seascape, coastal processes, water environment, other land and marine uses?).
- Economic and wider environmental benefits/disbenefits.
- Deliverability, including health and safety, design, routeing, ground/seabed conditions, topography, flood risk, land ownerships.

Within the planning system, assessing compatibility with other land and marine uses would normally be best achieved through the development plan system, whereby the use of land is considered in a given round of planning in the light of sound evidence to support land allocations. These spatial plans, together with the proposed system of marine plans, would be an effective means of assessing compatibility at a regional or local scale. However, the inter-regional and inter-national nature of the required infrastructure, together with programmed timescales for plan preparation (particularly marine plans), makes this a less expeditious solution for planning for CCS infrastructure.

In this instance, such spatial planning may need to be undertaken at a national scale in order to provide direction and clarity in individual planning/licensing decisions. The proposed National Policy Statements and Marine Policy Statement provide a means of achieving this. These policy statements would allow decisions to be taken on the basis of sound evidence relating to the need for CCS and the optimal locations for CCS infrastructure development, and through consultation with stakeholders. Broad environmental acceptability would be assessed through Strategic Environmental Assessment.

Detailed environmental acceptability is best assessed at the individual project level through the Environmental Impact Assessment Regulations (Town and Country Planning (Environmental Impact Assessment) (England and Wales) Regulations 1999 and Electricity and Pipeline Works (Assessment of Environmental Effects) Regulations 1990).

The identification and assessment of the economic and wider environmental benefits associated with CCS are required at both the plan making and individual project level in order to balance all the planning issues and inform the planning decision.

Deliverability issues such as health and safety may be best assessed at individual project level. However, consideration of the location and route of pipelines/storage sites is best carried out at a more strategic level on the basis of evidence to provide justification for combined pipeline routes/hubs/storage sites and in the light of knowledge of existing and planned coal-fired generating capacity.

6.3 Role of the Government in securing CO_2 transport routes

To benefit from efficiencies provided by a network of hubs and 'mains' for CO_2 transport and storage, and facilitate effective spatial planning, the routes and sites required for CCS infrastructure should be identified and safeguarded. A technical study to define routes for mains, hubs and storage sites will assist in providing the required evidence base. The robustness and usefulness of the various technical studies undertaken to identify appropriate routes and storage sites for CO_2 will be greatly enhanced if the studies are subject to consultation with key stakeholders in the marine and land use planning field and electricity generators. The final study should be technically sound and take account of views expressed during the consultation process.

The Government should provide national planning policy objectives for the achievement of CCS infrastructure provision. The proposed Marine Policy Statement and National Policy Statements provide the means for this. The statements should explain what factors are to be taken in to account in identifying routes and sites, drawing on the technical studies as well as planning policy/sustainability principles.

The implementation of objectives through safeguarding or allocating routes and sites for CCS infrastructure would normally be achieved regionally or locally through the existing system of development plans. Proposed marine plans provide a similar mechanism. However, the programmed timescales for such plans, together with the inter-national/regional and marine/land nature of CCS development, do not fit neatly in to such a mechanism. A section of, or annex to, the Marine and National Policy Statements would provide a means to safeguard routes and sites based on the objectives, principles and technical studies described above.

Until such policy statements and plans are in place, proposals for generating capacity that state they are 'carbon capture ready' must demonstrate this readiness by completing a conceptual pipeline routing study which demonstrates that at least one reasonable route to a CO_2 storage site (or area where it is expected that a number of CO_2 storage sites will be available) is likely to be able to obtain consent. These proposals should take account of emerging studies on CO_2 transport routes and seek to coordinate with any other existing or emerging proposals for power generation involving CCS.

Given the national importance of CCS infrastructure, the potential difficulties of dealing with both land and marine based planning and consenting regimes, the inter-regional and inter-national nature of the required infrastructure, and potential time delays; the Government may consider that decisions on proposals for CO_2 pipelines and storage sites should be dealt with by the proposed Infrastructure Planning Commission. For this to be achieved expeditiously, the completion and consultation on technical studies (the evidence base) and a clear statement of national policy should be given a high priority.

6.4 Role of the Environment Agency

The following bullet points list possible actions for the Environment Agency to consider in relation to planning issues:

- To seek clarification from the Government on the role of the proposed new Infrastructure Planning Commission. Is the provision of CCS infrastructure within its remit? Will/should the IPC have jurisdiction over marine developments?
- To emphasise the importance of the Marine Bill in introducing a marine spatial planning system and simplifying the marine consent regime. To consider whether special provision needs to be made for CCS consent through the Marine Bill.
- To contribute to the planning and marine policy statements dealing with CCS and associated infrastructure. To provide technical expertise on the wider environmental benefits provided by CCS and advise on environmental considerations to take into account in decision making in plans and on individual projects.
- To assist the Government (in collaboration with the new Marine Management Organisation and relevant planning bodies) to define routes/sites for CCS infrastructure.
- To consider whether (in its role as a statutory consultee) to object to applications for new coal-fired generation plants that have not produced reasonable evidence of capture readiness, including conceptual studies of capture retrofit and a conceptual study for a pipeline route to a reasonable storage location/area. Such an objection could be framed around the lack of demonstrable evidence that CCS can be achieved.
- Where applications include proposals for CO_2 pipelines and storage, utilise the checklist in the section above to judge the feasibility of the proposed routes.

7 Conclusions and recommendations

CCS is currently not viable, as the economics of CCS without enhanced oil recovery (EOR) and utilisation of former hydrocarbon assets suggests that the carbon price signal for Phase III of the EU ETS is insufficient both with regards to the level of the expected carbon price and to the potential fluctuations around that expectation. Given the high level of uncertainty with regards to CCS costs after demonstration, it is not possible to assess the CO_2 price threshold at which CCS would become viable with precision; however the ranges in published reports cited in the sections above include a £17/t CO_2 to £90/t CO_2 requirement. The minimum level of the range is expected to be an underestimate due to the age of the estimate.

Sustained high oil prices combined with the expected carbon signal may generate some CCS after the demonstration projects prove general commercial viability. With regards to CO_2 transport networks, if total volumes of CO_2 to be transported are well understood, least-cost network development will maximise use of hubs and trunks (mains) subject to environmental safety and constraints.

CCR is viable as there appears to be a reasonable business case for power plants in the UK sited with reasonable access to offshore storage to be made capture ready, i.e. when the location of the plant is not affected by CCR. This is because capture readiness minimises the risk of the plant becoming a stranded asset if carbon prices increase.

CCR means that space for both the large units of capture equipment and the many smaller ancillary items and interconnections with the original plant need to be provided and that there are no known impediments to transporting the CO_2 to storage.

CCR should be regulated rather than left to the operator, even though there is a reasonable business case for power plants in the UK sited with adequate access to offshore storage to be made capture ready. Regulation will ensure consistency and transparency and will help avoid technology lock-in.

CCR should be regulated under Section 36 but could also be under the revised IPPC Directive in the future. It is recommended that a formal requirement for plants to be capture ready is included in any future Section 36 plant permits in order to ensure consistency with the precedents already in place. It is also recommended that the Environment Agency engages in the specification and verification of capture readiness, possibly as an eventual extension of PPC, to ensure appropriate quality standards across the industry, to help engage and inform government efforts in CCS and CCR at a time of significant development, and to provide public reassurance that CCS is actually a future option for these plants.

CCR is likely to be required under potential revisions to the IPPC Directive, as indicated in the CCS Directive proposal.

Argument for centralised pipeline networks. Pipeline access onshore and offshore is of concern in ensuring CCR since many aspects of this are beyond the control of the plant proposer. Therefore there are arguments that support the case for wider planning for CO_2 transport. The Environment Agency could consider the following issues in relation to planning:

- The role of the proposed new Infrastructure Planning Commission in relation to the provision of CCS infrastructure.

- The importance of the Marine Bill in introducing a marine spatial planning system and simplifying the marine consent regime.
- Collaboration with the Government (and the new Marine Management Organisation and relevant planning bodies) to define routes/sites for CCS infrastructure.

Regulatory Framework for CCS. The regulatory framework for CCS itself is still very uncertain. This situation is likely to improve with the adoption of a CCS Directive, which is expected before the end of 2009, but further legislation will be required to cover all the relevant aspects. One of the uncertain areas is that of pipeline transport, which is covered by CCR definitions, but is not fully within the control of the operator. Regulation of pipeline access onshore and offshore therefore requires additional clarification. In this context, there are arguments that support the case for wider planning for CO_2 transport. The Environment Agency could consider the following issues in relation to planning:

- The role of the proposed new Infrastructure Planning Commission in relation to the provision of CCS infrastructure.
- The importance of the Marine Bill in introducing a marine spatial planning system and simplifying the marine consent regime.
- Collaboration with the Government (and the new Marine Management Organisation and relevant planning bodies) to define routes/sites for CCS infrastructure.

Recommendations

CCS is not currently commercially viable, but investment in fossil-fuel plants without CCR provisions would lead to risks of carbon lock-in. It is recommended that a formal requirement for plants to be capture ready is included in any future Section 36 plant permits for coal-fired stations. It is also recommended that the Environment Agency engages in the specification and verification of capture readiness, to ensure appropriate quality standards across the industry, to help engage and inform government efforts in CCS and CCR at a time of significant development, and to provide public reassurance that CCS is actually a future option for these plants.

In addition, the Environment Agency can support the development of CCS through the backing of a strong carbon price signal and facilitation of the development of a clear regulatory framework for CCS, including that of transport planning.

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Annex I: Criteria for assessing CCR applications

Technical requirements for capture readiness

Only the requirements for subsequent addition of post-combustion capture to pulverised coal plants will be discussed in detail here, although similar considerations will apply for addition of post-combustion capture to NGCC plants. Capture-ready (CR) requirements for oxyfuel plant are not discussed for the reasons set out in Box 1 below.

Box 1. Oxyfuel capture technology focus

Only the original boiler designer can credibly present a capture-ready design and associated conceptual capture retrofit study for a pulverised coal (PC) (or other) oxyfuel plant. This is because of the number of proprietary details in the original design that have to be right to handle subsequent conversion. Moreover, there is a very different level of uncertainty in assessing whether an oxyfuel CCR PC plant is going to work, compared to the same assessment for a post-combustion CCR PC plant. For the latter it only has to be assumed that some type of post-combustion capture technology will be available, not larger than current (conceptual) plants and requiring some combination of low-grade heat and electricity to operate it that can be accommodated in the current plant design.

For oxyfuel CCR PC plants it has to be assumed that the plant designer has allowed for all the necessary features of an oxyfuel capture version of the specific plant which they are specifying, since subsequent radical modifications will probably not be feasible. Currently, this must be done in the absence of any significant experience of this type of plant.

Space and steam cycle requirements for capture readiness

Space in capture-ready plants is better characterised as the scope to add the equipment expected to be required[34] for a capture retrofit. Leaving space is not only cheaper than pre-investing in additional equipment but also does not involve the risk of locking in to particular technology options that may quickly become obsolete. But space itself is only part of the issue. It is also very important to have space in the right places. And space is required not only for the capture equipment once it is in place but also for the process of installing it in such a way that the normal operation of the plant is not disrupted beyond a necessary minimum.[35]

[34] Expected, since the state-of-the-art technology retrofitted in the future is unlikely to be exactly the same as that used in a conceptual retrofit study for capture-ready plant design. This conceptual retrofit study is therefore likely to examine possible ranges of requirements for the capture equipment, including maximum or otherwise critical values, in addition to single estimated values describing the conceptual capture equipment.

[35] When plants are being built construction can be staged to allow elements to be added in a suitable order. For capture retrofit, not only will the rest of the plant be in place but it also has to be kept working through the months of construction, only being taken off-line for the final connections to be made. Access has to be maintained, staff have to be accommodated and

The most obvious space requirement is the land on which to erect the very large units used for post-combustion flue gas scrubbing, which will also have to be in an accessible location. The required footprint is significant, even when compared to the rest of the plant, and a lack of suitable space would probably be a ‘show-stopper’ for capture. Much less space is required to install other items of capture equipment, with some examples given below, but lack of space would still cause severe problems:

- Space is required to route the large offtake pipe carrying low-pressure steam from the steam turbines to the solvent reboiler. Blank lengths or removable spool pieces are required in the existing intermediate-pressure/low-pressure (IP/LP) turbine steam crossover pipes which can be modified to attach this offtake pipe and also to accommodate the large valves and other equipment that may be needed.
- Extra height (empty internal space) may be needed in the flue gas desulphurisation (FGD) unit to allow very high levels of capture to be achieved in the future.
- Extra cooling will be required, so space for equipment such as another cooling tower, more pumps and/or large enough cooling water intakes is necessary.
- The carbon dioxide compressors and gas cleaning/drying units will need to be sited with connections to the capture plant, to the CO_2 pipeline, to the necessary services (electricity, cooling water etc.) and also with scope to return ‘waste’ heat recovered after CO_2 compression to the steam cycle to reduce the energy penalty for capture.
- Extra space in the control room and connection panels etc. will be needed for the control equipment associated with the capture plant.
- Larger pumps and gas blowers will be required in several places.
- Large amounts of additional auxiliary electrical power will be needed to run the capture equipment, compressors etc. Space is required adjacent to the existing switchgear and transformers for station power to add additional units and also in cable ducts and racks for distribution.
- In a multi-unit station especially, it may also be useful to leave space for a complete new unit to be added at the time of retrofit to provide additional power to compensate for the capture energy penalty and restore the aggregate electrical output from the site. In this case space for additional features (e.g. low-pressure steam lines between units and a common CO_2 manifold and shared compressors) may also be required.

The ground area required for the main capture plant items (gas conditioning, absorber, stripper, compressor) needs to be determined for the actual site in question since the layout has to accommodate the rest of the plant and optimum spacing may not be possible. Access for construction is obviously also very site-specific. Published (IEA GHG 2006) estimated areas for a coastal seawater-cooled (i.e. no cooling towers) supercritical pulverised coal power plant with an original output of 500 MW are:

Area for standard 500 MW coal plant without capture:

$$400 \text{ x } 400 \text{ m} = 160{,}000 \text{ m}^2$$

Area for capture equipment:

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space on site has to be found to lay down equipment and materials as well as to erect the plant itself.

125×75 m = 9,500 m^2 (~ 6% additional land)

Area for 500 MW capture-ready plant (that will be able to export ~400 MW after capture retrofit with current amine capture technology):

412×412 m = 170,000 m^2

While these space estimates are sufficient for approximate cost impact assessments, as presented below, they cannot be more than initial benchmarks for individual plants. Sites are irregular and access requirements vary. A conceptual retrofit study undertaken for the actual power plant and site configuration can gauge whether enough space has been allocated for capture equipment on a particular site.

Steam cycle requirements, in addition to access space as noted above, are principally a suitable choice for the IP/LP crossover pressure so that significant energy penalties are avoided when capture is added (if the pressure is too high) or capture is not made infeasible (if the pressure is too low). The turbine supplier must provide assurances that the steam requirements and other steam/water cycle integration requirements for the conceptual retrofit study can be accommodated. A range of turbine design approaches are available to cope with the range of future operating conditions that may be required to accommodate capture technology developments (IEA GHG 2007). None of these are likely to detract noticeably from performance before capture is added or to add significant costs.

Financial implications of space requirements at the power plant site

According to the Impact Assessment of the proposed EC CCS directive (EC 2008b), the average cost of securing the area required is limited in comparison to the overall investment costs for the plant. The Impact Assessment provided an example of a coal-fired plant with a capacity of 400 MW, suggesting that the land area requirement for CCR is between 5,000 and 7,500 m^2. Allowing for the difference in plant output, the higher value is close to the 9,500 m^2 cited in Section 2. Land cost assumptions of the EC vary from £2(€2.50)/m^2 for bare soil, to £14(€20)/m^2 for outside city area, to £24(€35)/m^2 for city area. Assuming a capital cost estimate of a power station without CCS of £1,017 (€1,500)/kW, the cost requirements for the land area would constitute between £14,000 (€19,000) and £178,000 (€263,000) for the 400 MW plant and £16,000 (€24,000) and £226,000 (€333,000) for the 500 MW plant, or 0.003 to 0.04% of the capital cost. These estimates are subject to uncertainties related to land value and capital cost estimates.

A large proportion of new power stations are erected in the place of decommissioned plants (brownfield developments). This has a large impact on the success of planning and grid-connection applications. However, additional land required for the capture equipment and for the additional capacity to fuel the capture in a brownfield site can be difficult to acquire, depending on location.

Of the approximately 25 new >300 MW power stations in the UK that could potentially be commissioned over the next five years, based on current public domain information, at least one-third would be erected in place of decommissioned plants and a further third built as extensions or adjacent to existing power stations. Most of the remaining plants are planned for other brownfield sites. In almost all cases there is vacant land in the immediate vicinity of the site, which could potentially be used to expand the size of the site to accommodate carbon capture. However, this would be subject to a number of factors, including suitability, planning consent, availability and cost.

Other financial impacts: feasibility study and location

The direct, obvious financial impact of other *de minimis* CCR requirements such as proving that a feasibility study has been undertaken and an adequate transport route and storage have been identified is likely to be very limited and to be expressed in terms of cost of staff time.

An exception to this could be if the requirements are translated into the need to change the location of a plant in order to ensure access to transport and storage since this would entail significant costs. This should be unlikely in cases where the plant location has been planned with capture readiness in mind since unsuitable sites should have been rejected at an early feasibility study stage.

In conclusion, the basic CCR requirements are that space for both the large units of capture equipment and the many smaller ancillary items and interconnections with the original plant should be provided and that a conceptual retrofit study should be undertaken to verify feasibility. In addition, the steam cycle should be capable of providing a range of possible extraction flows for solvent regeneration in a reasonably efficient manner. There must also be credible prospects that CO_2 from the site can be transported to storage – see below.

Transport route requirements

In assessing the feasibility of potential CO_2 pipelines, the most intuitive parallel is with the appraisal of proposed natural gas pipelines. However, there are some key differences in undertaking the assessment of a transport route as part of 'capture-ready' authorisation and the feasibility assessment of a proposed natural gas pipeline: for natural gas pipelines, the guidelines are defined. Also, they refer to an actual project rather than to 'readiness' for the project as is the case for CCR. Therefore it is recommended that the same issues as for natural gas pipelines are considered, as is done below, but taking into account the uncertainty surrounding CCS.

Ability to obtain consent

It should be necessary for capture-ready power plant developers to provide reasonable evidence that at least one route from their proposed plant to a reasonable storage site (or area where storage is expected to be available) is likely to be able to obtain consent. This could be demonstrated by a high-level review that includes issues that may prove problematic during permitting such as:

- Environmental acceptability considering aspects such as visual impact, ecology (protected species and habitat), flooding and hydrological assessment, ground conditions including stability and contaminated land.
- Health and safety (see separate item below).
- Design (see separate item below).

Consent may fall under a number of different authorisations, including Section 36, Town and Country Planning Act, Pipeline Authorisation Act, Petroleum Act or a combination of the above, but the issues considered will be similar.

Pipeline route: land ownership and wayleaves

There is a need to demonstrate the existence of an **appropriate corridor** for the pipeline. Supercritical CO_2 is yet to be classified by the Health and Safety Executive, so detailed requirements such as distances of wayleave or typical requirements for avoiding densely populated areas are not yet known. A conceptual study for possible CO_2 transport routes should take into account possible future requirements outlined here that are based on typical requirements for high-pressure gas pipelines. It is not expected, however, that a detailed survey of a proposed route would be undertaken during the capture-ready permitting process.

The onshore section of the pipeline may normally require 30 metres of wayleave. For segments where this is not possible, alternative measures can be used such as extra-thick walls for the pipeline, but the economics of this would have to be assessed carefully for large portions of the pipeline. It is not recommended that power line corridors are used, as induced power/secondary currents in the pipeline could cause corrosion. It should be possible to use routes for existing natural gas pipelines.

The pipeline should **avoid densely populated** areas by about 10 km.

Information on land ownership for the pipeline route and corridor could also be considered as part of the feasibility study and an assessment of **land-ownership issues** undertaken.

Consideration of a beach station and any other compression en route may have to be included in the assessment.

Health and safety

Capture-ready power plant proposers should provide a conceptual study of at least one retrofit option that can be reasonably expected to be viable with technology that is commercially available (or close to commercially available) at the time of the application for a permit for the capture-ready plant. This conceptual study should take into account health and safety requirements for the CO_2 capture, transport, compression and handling system that is proposed to be retrofitted. Depending on the level of detail of the study provided, the following issues should be considered and/or expected approaches for addressing these issues in later, more detailed, design work should be identified.

- Particularly where use of CO_2 networks, probably including gas hubs (i.e. not a point-to-point pipeline from source to CO_2 store), is envisaged, measures for ensuring gas quality control should be included.
- Provision against major leaks needs to be made, as well as appropriate systems to ensure that CO_2 is detected rapidly after any leak occurs.
- For pipeline safety, allowance for the fact that the seals of the equipment are affected by the presence of CO_2 will be needed in the case of re-use of existing gas pipelines.
- Societal risks of multiple fatalities would have to be considered since this is expected to be a requirement for HSE.

Design

It is not expected that detailed pipeline design would be undertaken by the proposer of a capture-ready power plant. The conceptual study for capture retrofit should, however, show awareness of relevant design codes with associated implications for approximate expected costs for CO_2 transport.

While supercritical CO_2 has not been classified yet, pipelines will be expected to adhere to an appropriate pipeline code (e.g. BS PD 8010 code, which applies for high-pressure steel pipelines). On the basis of experience with natural gas pipelines, it is currently expected that the pipeline would have to be designed to class E, and where appropriate the wall thickness must be increased.

When there are plans to re-use existing gas pipelines, the operator must ensure that the proposed pressure is appropriate for the pipeline age and condition and checks are planned for. It is likely that pipelines as old as 20 years could be used in this case; for example, a pipeline that was initially designed to operate at 100 bar pressure may require the pressure to be lowered to 30 bar.

The Environment Agency should give careful consideration to the cases where:

- There is insufficient information on the items above.
- It is obvious that there is obstruction to building a CO_2 pipeline out of the site (e.g. the power station itself is obstructing the exit route). However, it should be noted that, when it is obvious that there is no above-ground exit potential from the power station, it is possible to employ directional drilling techniques for up to 3–4 km,[36] for example when there is a requirement to cross a major estuary. This is commonly used in the natural gas industry.
- With regards to storage, the Environment Agency should pay particular attention to proposals including use of aquifer storage, as the integrity of these is more difficult to prove than that of depleted gas fields for example. It should be acceptable, however, for a pipeline routing study for a capture-ready plant to demonstrate that (i) an area with suitable geology and, hence, numerous potential storage sites can be reached and (ii) a reasonable approach to proving a site for storage as part of the detailed design of the capture retrofit has been identified.

[36] For example see http://www.stocktondrilling.com/

Annex II: An overview of capture-ready issues for natural gas combined cycle power plants

Range of basic capture options

Basic options for capture with NGCC – new build and general performance and cost issues

The relative performance of the three basic capture options for natural gas combined cycle (NGCC) plants is given in Figure II.1. This shows a 20% lower levelised electricity cost for post-combustion capture than pre-combustion capture when using natural gas, and an estimate for the latter technology to be slightly cheaper for coal. Oxyfuel gas turbines are predicted to be slightly more expensive still, but these would require a completely new gas turbine engine to be developed, a process taking perhaps tens of years, by which time it would probably be obsolete and superseded by alternative capture technology. It appears unlikely that this jump in technology will be attempted soon (although novel natural gas oxyfuel approaches could be – see Section 3). Oxyfuel gas turbines, of the type described in Figure II.1, which are essentially 'conventional' gas turbines using synthetic air made from CO_2 and oxygen, will not therefore be considered in this report, which will only consider post- and pre-combustion options.

The relatively weak performance of the pre-combustion option for gas can be explained by a number of factors:

(a) The same power cycle is being used for both pre- and post-combustion with gas. With coal, pre-combustion has the unique advantage of being able to use the more efficient combined cycle with internal combustion and hence higher peak cycle temperatures.

(b) The intrinsic efficiency of the pre-combustion combined cycle is reduced because peak firing temperatures have to be lower with hydrogen-rich gas due to the greater water vapour content of the combustion products and hence heat transfer to the blades. Limited anecdotal evidence suggests that this may amount to as much as 2 percentage points penalty, although manufacturers would have to be consulted on the performance differences for specific turbines when firing natural gas and hydrogen-rich fuels.

(c) The mass flow through the gas turbine is reduced because the H_2 is lighter than the CO it replaces, with a consequent loss of power.

(d) Both making a syngas (CO/H_2 rich mixture) from natural gas and then shifting the CO to hydrogen give rise to thermodynamic losses. Chemical energy is degraded to heat in both steps, which cannot then be used as efficiently to make electricity.

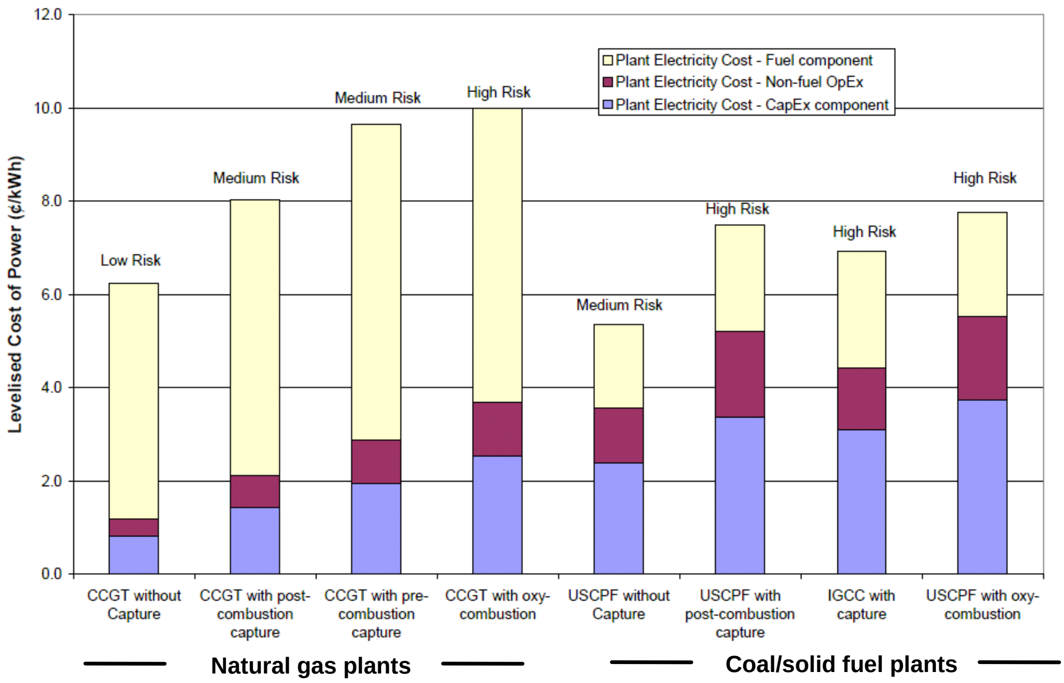
Against this must be set two factors:

(i) CO_2 capture and compression from the pressurised, low-volume gas stream after the steam reformer in pre-combustion plants involves a lower energy penalty and uses smaller, and hence cheaper, equipment than post-combustion capture on NGCC.

(ii) Large autothermal reformers, steam reforming and CO_2 capture/hydrogen purification are all relatively well-known technologies from the petrochemical and chemical industries (where they are used to make particular products rather than capturing CO_2). This is in contrast to post-combustion capture units, which are used on relatively large gas-fired steam reformers on ammonia plants to collect CO_2 for urea production, but are not yet employed at scale on NGCC plants – since that would have no other purpose than CCS.

The problems for post-combustion in (i) above could, however, be reduced by recycling flue gas in the gas turbine. This would simultaneously reduce the flue gas volume to be treated and increase the CO_2 concentrations, reducing capital costs and capture energy requirements per tonne of CO_2 respectively.

Because flue gas recycling developments are ‘leading edge’, it is difficult to cover them in any current discussion of capture ready approaches for NGCC. It may, however, even now be feasible to elicit some information from manufacturers since it would be reasonable for them to use the prospects of a particular turbine being modifiable for flue gas recycling in the future, and hence being more capture ready, as a selling feature in some markets.



IEA GHG (2006), CO2 capture as a factor in power station investment decisions, Report No. 2006/8, May 2006

Costs include compression to 110 bar but not storage and transport costs. These are very site-specific, but indicative aquifer storage costs of $10/tonne CO2 would increase electricity costs for natural gas plants by about 0.4 c/kWh and for coal plants by about 0.8 c/kWh.

Figure II.1 Relative levelised electricity costs for new build power plants

Retrofit of CO_2 Capture to Natural Gas Combined Cycle Power Plants (IEA GHG 2005a)

This study, by Jacobs Engineering, examined a range of capture options specifically for retrofit to NGCC:

- post-combustion;
- pre-combustion from gas on and off site;
- pre-combustion from coal on and off site.

The on-site pre-combustion option appears to be similar to the Peterhead project that was proposed by Beyond Petroleum and Scottish and Southern Energy (but was cancelled during 2007).[37] The post-combustion project used mono – ethanol amine MEA.

Results for levelised costs of electricity are shown in Figure II.2. As was stated in the IEA GHG report, however, they had not used information for 'state of the art' current post-combustion solvents (as proven in commercial steam reformer capture units by Fluor and MHI), so may have significantly overestimated potential post-combustion retrofit costs.

> IEA GHG has recently published cost and performance data for post combustion CO_2 capture in new power plants, on the same basis as this study 1. The cost of post combustion capture in a new natural gas combined cycle plant was estimated to be $37–41/tonne of CO_2 emissions avoided, compared to $73/tonne in the corresponding retrofit case in this study. ……. This retrofit study is based on information provided to Jacobs by UOP, for a conventional MEA scrubbing process. IEA GHG's study on new plants was based on data provided by Fluor and MHI are for their improved scrubbing processes (Econamine FG+ and KS-1), which have much lower steam consumptions for solvent regeneration. The efficiency penalty for post combustion capture in this study is 11.3 percentage points but the penalty is 8.2 and 6.0 percentage points in Fluor and MHI's studies. The specific capital cost penalty for CO_2 capture in this retrofit study is approximately twice as great as in IEA GHG's new plant study. The data provided by UOP is conservatively based on eight parallel CO_2 absorbers, compared to 3 and 2 in Fluor's and MHI's studies. The resulting economies of scale account for a significant proportion of the cost difference. Despite the conservative data used for post combustion capture in Jacobs' study, post combustion capture is still the lowest cost retrofit option. Use of Fluor's or MHI's processes would not have affected this conclusion.

[37] http://www.bp.com/sectiongenericarticle.do?categoryId=9007871&contentId=7014998

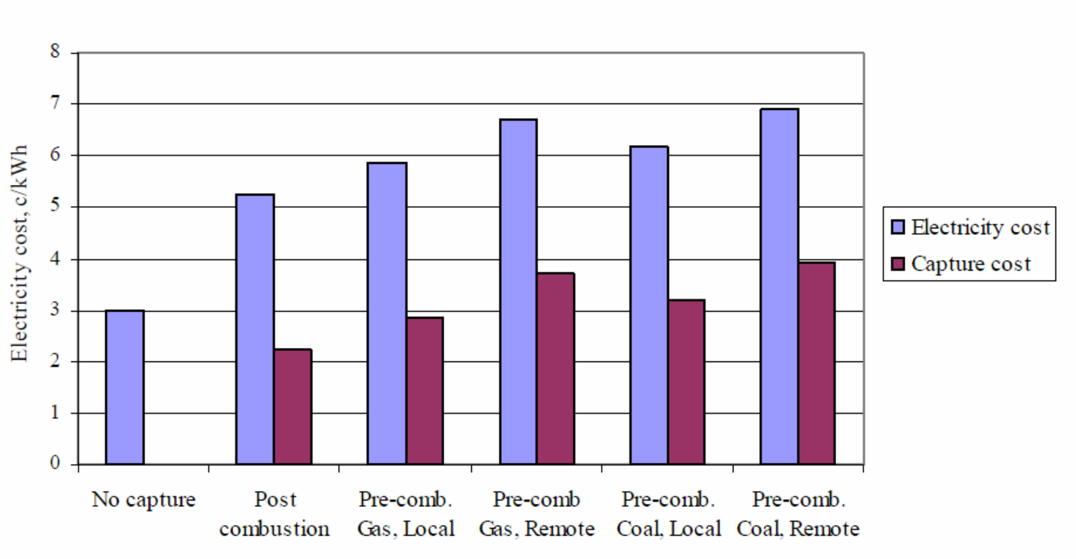


Figure II.2 Levelised cost of electricity for a range of capture retrofit options for NGCC (IEA GHG 2005a)

Ongoing activity in the field of NGCC with capture

There are several examples of NGCC with capture projects being planned or undertaken, particularly in the Middle East and Norway. Some key developments are described below.

Middle East

Ongoing work on CCS in Abu Dhabi may be taken up elsewhere in the Middle East. The attraction is to replace natural gas now being re-injected into oil fields to maintain pressure with CO_2. At present a post-combustion capture retrofit project on (presumably) a natural gas-fired power plant is being considered:

In Masdar there are two important CCS initiatives. It was recently reported in Middle East Business Intelligence (Meed)[38] that the first site for carbon capture plant in the planned carbon-neutral city of Masdar has been identified from two shortlisted sites – one industrial and the other oil-related. The facility is reportedly an existing power plant and 'under the proposed plan carbon dioxide emissions from the power plant will be captured postcombustion and transported by pipeline to oil fields in the emirate. The gas will be used by Abu Dhabi National Oil Company (Adnoc) to maintain oil reservoirs by injecting it into the fields'. The scheme, if successful, will lead the way for additional schemes which could potentially be introduced at a rate of one a year. Masdar is being set up as a free zone, exempt of tax in an attempt to encourage investors, particularly the Chinese, whom they are looking to for both investment and as a source of technology and manufacturing expertise.

Also in Masdar, Hydrogen Energy and Abu Dhabi-based Mubadala Development Company have entered into a project to develop an industrial-scale hydrogen-fired power generation project.[39] The project includes carbon capture and storage of the associated CO_2, which is to be captured and stored in geological formations and/or

[38] http://www.meed.com, Masdar selects site for Abu Dhabi carbon-capture facility, 4 April 2008.
[39] http://www.ameinfo.com/146300.html Herbert Smith advises Hydrogen Energy on plan to build clean power plant in Abu Dhabi, 10 February 2008.

potentially for enhanced oil recovery. Detailed engineering design is due to commence shortly and the project aims to begin commercial operation in 2012.

Norway

Norway's reliance on natural gas for fossil power plants (since the majority of the rest of Norwegian power is provided by hydro resources or electricity imports), its environmental consciousness, a confident industrial base and a government prepared to fund CCS development have led to a number of likely projects. There have, however, been some setbacks.

Norway has made clear its intentions to lead the development of CCS technology with the 2008 budget including provision of $2,261 million for carbon capture research.[40] They hope to gain a head start in the industry that is projected to be worth millions. However, it is felt that Norway remains at a disadvantage in this regard as its efforts will be based on gas-fired plants rather than coal. Gas-fired technology is currently considered a more difficult technology.

As part of this focus, CCS facilities are to be developed at the Karsto power plant in Norway by Gassnova SF.[41] Firms are currently undertaking front end engineering and design (FEED) studies and will thereafter compete for the construction contract which includes constructing CO_2 capture facilities, installing pipelines for CO_2 transport and storing the CO_2 in geological formations. Investment decisions are expected to be made in autumn 2009. The work is to be based on the report *'CO_2 Management at Karsto'* undertaken by the Norwegian Water Resources and Energy Directorate (NVE) in 2006, which outlines technical, financial and timing considerations for the work.

Possible future options for CO_2 capture from natural gas

An interesting variation on the three routes already identified for CO_2 capture from natural gas has recently been described in public.[42] This is based on a high-pressure oxygen/gas burner with integrated water injection, developed by Clean Energy Systems (CES) in California. The water cools the burner and evaporates to give a steam plus CO_2 working fluid. The concept, developed by a team led by Jacobs Engineering in the UK (which has been entered as a post-combustion/oxyfuel capture option for the UK CCS Competition[43]), is based on the gaseous fuel coming from a coal gasifier. But the original CES burner (see Figure II.3) was developed on natural gas and, if the technology proved successful, a similar approach might be suitable for new natural gas capture plants or possibly for repowering existing NGCC units, since a conventional steam cycle forms part of the unit (Figure II.4).

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[40] http://www.reuters.com/articlePrint?articleId=USL14746392, INTERVIEW – Norway may fall short in carbon burial race, by Alister Doyle and Wojciech Moskwa, Friday 14 March 2008.
[41] Gassnova Press Release, 5 March 2008.
[42] Coal Research Forum, 19th Annual Meeting, 10 April 2008: 'Current development in coal research', John Griffiths, 'IGSC – A pressurised oxyfuel cycle that uses water as a coolant'.
[43] http://www.berr.gov.uk/energy/sources/sustainable/carbon-abatement-tech/ccs-demo/page40961.html.

Figure II.3 Original CES burner installation in California; T-piece at end connects to steam turbine

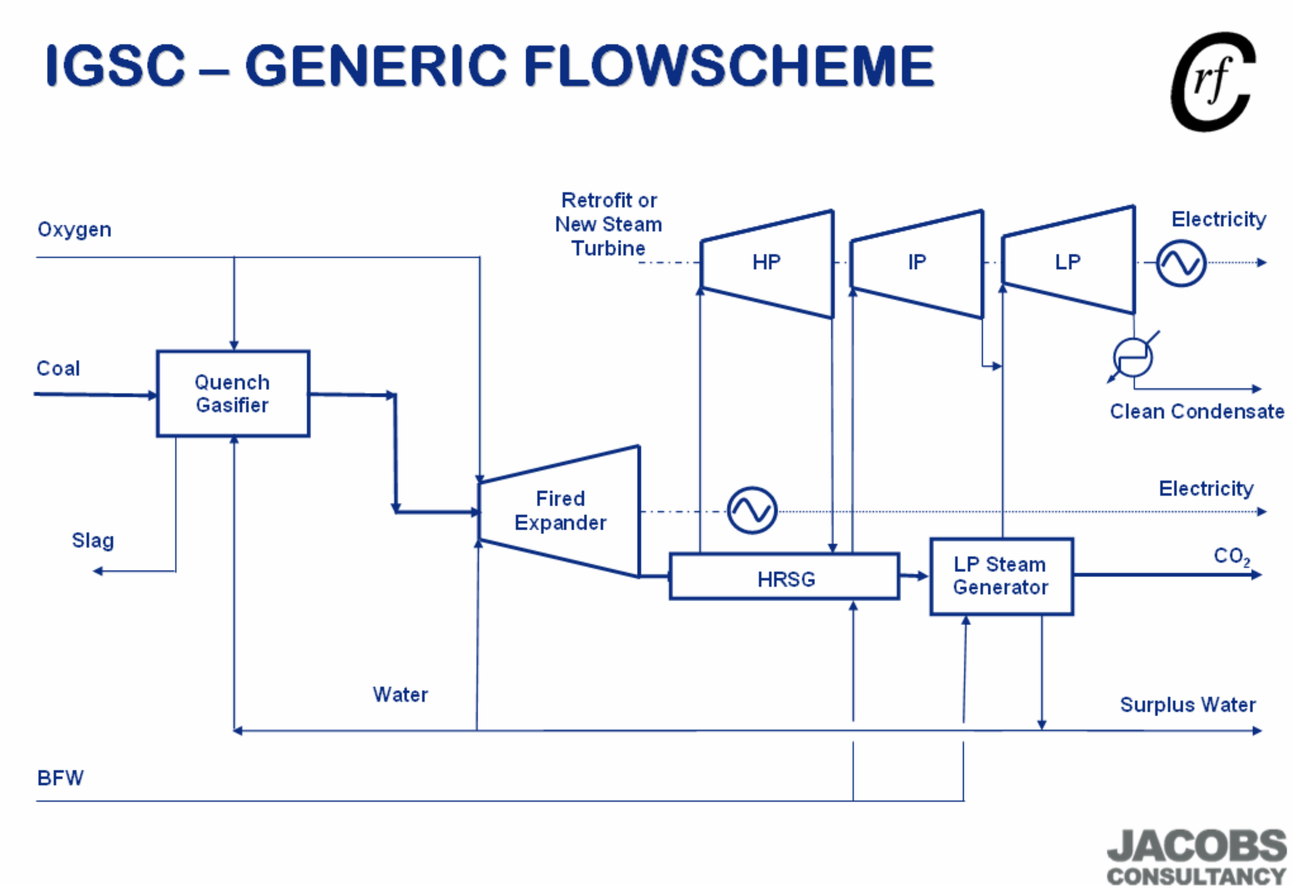

Figure II.4 Integrated gasifier steam cycle concept flow scheme

Equipment configuration issues – steam turbine considerations for capture-ready NGCC

As part of ongoing work at Imperial College, London, on capture-ready power plant, funded by the Research Council's TSEC programme and by BERR, a draft paper on capture-ready NGCC plants has recently been prepared and submitted for peer review and publication in the IMechE *Journal of Power and Energy*. Although obviously without the authority that comes from the scientific review process, this paper concluded that:

> *When an NGCC plant is designed to be ready for the retrofit of post-combustion capture, one of the most important technical considerations is the steam extraction pressure and flow to provide the heat demands for solvent regeneration. The pressure and flow are determined by the solvent used, but new solvents are being developed and the exact future requirements, in perhaps 10–20 years time, cannot be predicted. In addition extracted steam flows for solvent regeneration may deliberately want to be adjusted over a wider range to provide additional operational flexibility.*
>
> *Some possible designs for steam cycles for NGCC plants are presented. The objective is to maintain the competitiveness of a CCR plant built today and retrofitted in the future, compared to a future new-build plant with capture. Finally, several alternatives to mitigate the loss of power output of retrofitted NGCC plants will be assessed and compared.*

The principal conclusions are that:

> *Natural gas combined cycle plants can be made ready for post-combustion CO_2 capture systems with very little modification to their original design and without any significant additional up-front investments or change in performance. Additional space for the addition of a capture plant and the location of the plant itself are important criteria for capture ready plants independent of the technology or the choice of fuel. The loss of power plant output generated by a post-combustion capture plant can be reduced at times where electricity value is high through different operating strategies increasing plant capacity factor compared to a non-flexible NGCC plant retrofitted with post-combustion capture. Options to build additional steam/electricity generation units to avoid a reduction in plant output when capture is added could be considered but, because they are likely to give a higher energy penalty per tonne of CO_2 captured, should not substitute for making the main steam cycle capture ready. NGCC plants could both capture CO_2 and provide district heating with a high degree of thermal integration since capture makes greater amounts of heat available below the LP evaporator pinch temperature.*

Relevant experience and plans for NGCC fleet

Lifetime for existing NGCC fleet vs PC fleet

A 'reasonable' economic lifetime for an NGCC power plant is expected to be around 20 years, but modern NGCC plants really only date back to the 'dash for gas' in the 1990s, so little data on their achieved lifetimes is available. What little there is (see Table II.1 below) suggests this estimate may be approximately correct, but the sample is too small for any very meaningful conclusions to be drawn. Also, other factors (e.g. nuclear closures and the effect of the LCP Directive in the present market) would also be expected to affect any current lifetime decisions for the existing fleet.

Experience to date does not contradict an expectation that new coal plants will be in service for much longer than new NGCC plants currently being built. The UK coal fleet has a demonstrable service life of 30–40 years already, with the prospect of life extensions for many plants to 2016 through opting in to the LCP Directive and fitting Flue Gas Desulphurisation (FGD) where necessary, plus indications that some will have their life extended beyond 2016 through the installation of Selective Catalytic Reduction (SCR). There is thus a greater likelihood of needing to retrofit coal-fired power plants with capture than NGCC plants. Current experience does not, however, provide sufficient evidence to prove this suggestion.

Table II.1 Existing UK NGCC plants from BERR 2007b - DUKES (plants operational in May 2007)

Station Name	Fuel	Installed	Year of commissioning	Location	Date for possible equipment replacement	Age at replacement
Ballylumford C	CCGT	616	2003	Northern Ireland		
Barking	CCGT	1000	1994	London		
Barry	CCGT	245	1998	Wales		
Connahs Quay	CCGT	1380	1996	Wales		
Coolkeeragh	CCGT	408	2005	Northern Ireland		
Corby	CCGT	401	1993	East Midlands		
Coryton	CCGT	732	2001	East		
Cottam Development Centre	CCGT	400	1999	East Midlands		
Damhead Creek	CCGT	792	2000	South East		
Deeside	CCGT	500	1994	Wales		
Didcot B	CCGT	1390	1998	South East		
Enfield	CCGT	392	1999	London		
Fife Power Station	CCGT	120	2000	Scotland		
Glanford Brigg	CCGT	268	1993	Yorkshire and		
Great Yarmouth	CCGT	420	2001	East		
Keadby	CCGT	745	1994	Yorkshire and		
Killingholme	CCGT	665	1994	the Humber		
Killingholme	CCGT	900	1993	Yorkshire and		
Kings Lynn	CCGT	340	1996	East		
Little Barford	CCGT	665	1995	East	**2012**	17
Medway	CCGT	688	1995	South East		
Peterborough	CCGT	405	1993	East		
Rocksavage	CCGT	748	1998	North West		
Roosecote	CCGT	229	1991	North West		
Rye House	CCGT	715	1993	East		
Saltend	CCGT	1200	2000	Yorkshire and		
Seabank 1	CCGT	812	1998	South West		
Seabank 2	CCGT	410	2000	South West		
Shoreham	CCGT	400	2000	South East		
South Humber Bank	CCGT	1285	1996	Yorkshire and		
Spalding	CCGT	860	2004	East Midlands		
Sutton Bridge	CCGT	800	1999	East	**2010**	11
Teesside Power Station	CCGT	1875	1992	North East		
Oldest			**1991**			

Table II.2 Existing UK pulverised coal plants from BERR 2007b - DUKES (plants operational in May 2007)

Station Name	Fuel	Installed MW	Year of commissioning	Location
Lynemouth	coal	420	1995	North East
Eggborough	coal	1960	1967	Yorkshire
Drax	coal	3870	1974	Yorkshire
Cottam	coal	2008	1969	East Midlands
West Burton	coal	1972	1967	East Midlands
Ironbridge	coal	970	1970	West Midlands
Ratcliffe	coal	2000	1968	East Midlands
Rugeley	coal	1006	1972	West Midlands
Aberthaw B	coal	1455	1971	Wales
Cockenzie	coal	1152	1967	Scotland
Longannet	coal	2304	1970	Scotland
Uskmouth	coal	393	2000	Wales
Ferrybridge C	coal/biomass co	1955	1966	Yorkshire
Fiddler's Ferry	coal/biomass co	1961	1971	North West
Didcot A	coal/gas	1958	1972	South East
Kilroot	coal/oil	520	1981	Northern Ireland
Kingsnorth	coal/oil	1940	1970	South East
Tilbury B	coal/oil	1038	1968	East
			1966	

Factors that may affect the decision to retrofit capture to NGCC

A more relevant case to examine might be whether or not, when faced with a driver to fit CCS, an NGCC plant owner would be likely to retrofit CCS to an existing plant or to build a new plant.

Factors to consider include:

(a) Equipment not very expensive but fuel is – demolish and start again.

(b) May be need for low load factor plants in future generation mix.

(c) Gas demand in buildings may go down and electricity demand up – insulation and heat pumps instead.

(d) LNG lifecycle emissions (cannot be reduced by CCS).

(e) Marginal operating cost trends for NGCC+CCS (leading to 'merit order' position and load factor).

It is interesting to note that the linked factors (a) and (b) differ significantly from expectations for coal, the latter being a relatively cheap fuel requiring expensive plants. Thus, when considering retrofitting an NGCC plant a utility may decide to build a new plant in a location with minimum transport and storage costs and possibly able to use better technology, since the extra fuel required for a less efficient installation can be balanced successfully against the extra capital cost of a new plant (see Figure II.1). This point is also made in the Stern Review's coverage of CCS, as illustrated in Figure II.5.

Because of relatively high fuel costs for natural gas it is also more likely that natural gas plants will be the ones used only to meet peak power demands and therefore will only achieve low load factors, perhaps 30% or less. These low load factors have several consequences for retrofitting CCS. CO_2 emissions to atmosphere are obviously much lower than for baseload plants. The economics of CCS retrofit are also much worse, since the capital costs for the capture equipment itself and any pipeline additions must be paid off over a much smaller number of operating hours. Finally, it may prove technically difficult to operate capture plants, CO_2 compression systems and pipelines with highly intermittent CO_2 sources.

Relegating older ‘low merit’ plants to peaking duties is standard practice in the electricity industry since it gives the lowest possible overall electricity costs. Such plants would, of course, still be liable to operate within the EU emission cap and hence purchase emission allowances.

In the future, if capturing CO_2 from fossil fuels became mandatory, it might also be feasible for a somewhat analogous process to be applied to CCS (i.e. for a trading scheme based on stored CO_2 to be developed, in addition to or instead of trading in CO_2 emissions allowances). The quota for CO_2 to be captured from a plant would be set independently but it might be possible for additional CO_2 captured and stored elsewhere, presumably at UK sites where it could be done more efficiently, to be set against that quota. The instrument to do this might be a tradable CO_2 Storage Certificate. At least for an interim period this could achieve identical climate benefits, but at a lower cost. Such a mechanism would also have the effect of shifting fossil generation capacity over this period to locations that facilitated CCS, by transferring income to them from plants in less favourable locations. Given the expected relatively short life of NGCC plants, their closure at the end of such a transition period, when higher required levels of capture in the power sector made meeting CCS obligations by trading less feasible, might fit in fairly well with natural capital stock turnover.

The economic viability of using CCS technology for power companies will reflect both the relative price of coal and natural gas and the level of the carbon price. Should the carbon price reach a sufficient level, with a credible expectation that it will remain there, widespread deployment of CCS can be expected. The choice of technology will also depend on the price of different fossil fuels, so if gas prices are high then coal will be chosen as shown in the figure below.

Impact of carbon and energy prices on CCS deployment

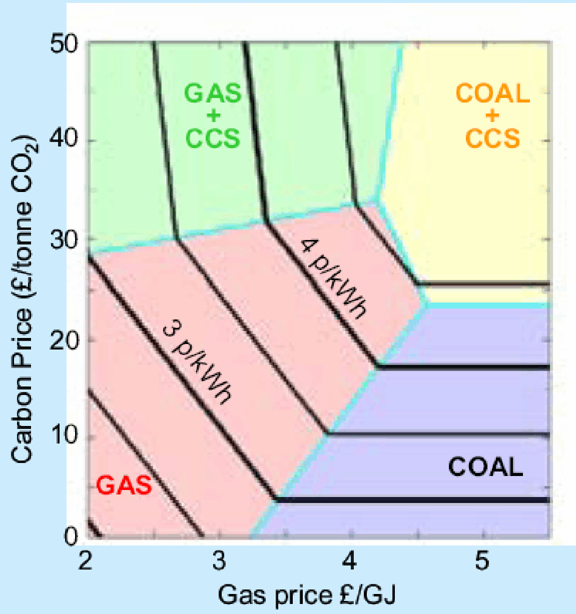

Figure II.5 Differing economics for gas and coal as a function of relative fuel prices (graph from Gibbins et al. 2006b)

Conclusions and recommendations

- In a period of technical and regulatory uncertainty, firm recommendations for possible future actions to add CCS to NGCC power plants are difficult to make since a number of options appear to be available.
- It appears possible that the owners of many NGCC plants may not opt to capture CO_2 at all, but will operate the plant at low load factors if tighter carbon restrictions come into force.
- This is in contrast to coal plant operators, and a natural consequence of the likely shorter lifetime for NGCC plants, their lower capital costs relative to coal plants and their higher fuel costs.
- It might be feasible to make plants that elected not to fit CCS to support CCS elsewhere by way of recompense, through an appropriate mechanism (e.g. tradable CO_2 Storage Certificate). This would be expected to encourage a transition in the fossil power generation industry to sites (and technologies) that favoured CCS.
- It appears, however, that post-combustion capture of CO_2 represents the lowest-cost option for capture from NGCC based on present studies and that this technology will be developed to commercial availability in the near future (and probably ahead of other options).

- It also appears that NGCC steam cycles could be designed to accommodate post-combustion capture with negligible performance penalty and cost. Additional costs for land would also be fairly low (and, ultimately, recoverable to some extent if the capture option is not exercised).
- It therefore appears reasonable to require NGCC plants to make provision at least for post-combustion capture of CO_2 as a low-cost 'insurance' policy against uncertain national requirements unless there are compelling reasons to consider that alternative options (e.g. hydrogen from an established network) will be available.
- Transport of CO_2 from some NGCC sites may be uncertain (as discussed elsewhere) but possibly instruments such as a tradable CO_2 Storage Certificate may assist storage on sites that alone could not justify the cost of the necessary infrastructure, by effectively channelling funds from a number of sites to that location to undertake a higher level of CCS on their behalf.

Annex III: The economics of hubs and mains

Summary conclusions

In most studies reviewed as part of this project, cost estimates for transport are commonly based on the costs of natural gas pipelines. Construction costs make up the bulk of the costs involved, with materials representing a considerable proportion of construction costs, as well as labour. According to Parfomak and Folger (2007), which was prepared for the US Congress, material costs constitute between 15 and 35% of the total construction costs of a pipeline while labour costs constitute about 45%. As the diameter of a pipeline increases, costs increase sublinearly, while throughput increases exponentially (IEA 1994). Figure III.1, from MIT (2007), shows the relationship between volumes transported and unit costs.

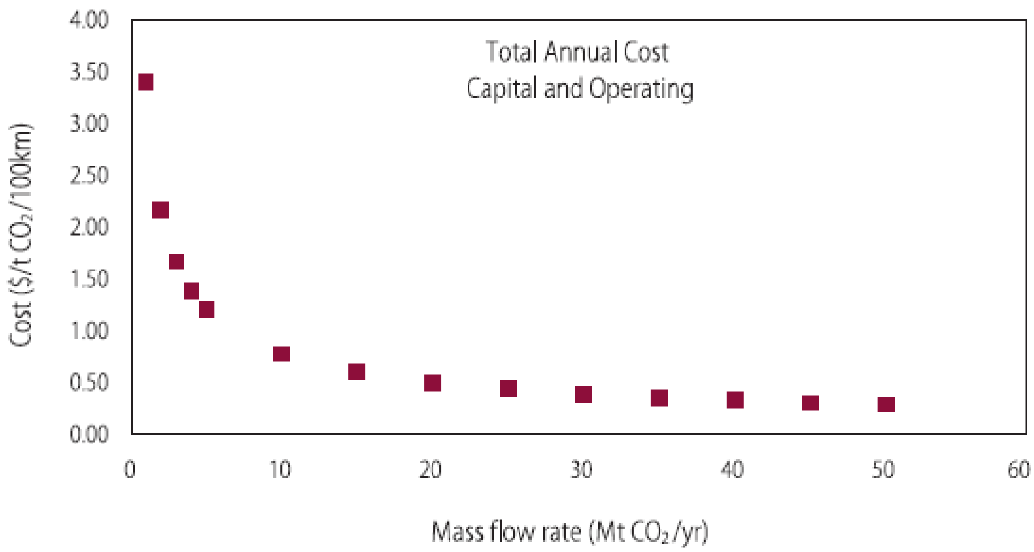

Figure III.1 Unit transport costs vs. total volume transported

The theory behind using hubs and mains to benefit the economics of CO_2 transport is that this approach reduces the length of pipeline needed through use of larger diameter pipes. Despite the intuitive theoretical advantage of hubs and trunks compared to individual project pipelines from source to storage, not all of the recent studies (including IEA GHG (2005b), Element Energy et al. (2007) and Poyry (2007)) are conclusive about significant cost savings ensuing from hubs and mains. The reasons for the inconclusive results may include:

- Some degree of aggregation is included in the source-to-storage scenarios (e.g. use of offshore mains and individual onshore pipelines).
- Backbones are compared with individual pipelines that are in fact re-used existing gas pipelines, used for enhanced oil recovery.

- Integrated transportation and storage modelling, with a focus on storage classification and minimisation of storage costs.

Summaries of the analysed studies are presented below.

The key types of networks considered for the UK include:

- offshore trunks towards storage with either individual pipelines to the offshore trunk or onshore network (Poyry 2007);
- re-use of existing gas pipelines, with individual connection between sources and storage (EEEGR 2006);
- use of individual pipelines throughout Europe (IEA 2005);
- use of European backbones covering the UK (IEA 2005).

In the current regulatory, technical and commercial uncertainty about CCS, the following inferences can be made about the likely transport network scenarios:

- Under continued uncertainty, there is a high chance that in the UK the first projects to be developed would use existing gas infrastructure, both because this would reduce the investment cost in pipelines and also because these pipes lead to depleted gas fields, which are the most straightforward storage option (Element Energy et al. 2007).
- If re-use of existing gas pipelines is widespread in the initial stage of network development, it is likely that hubs will be formed at the current seven gas beach terminals.

  The EC published a map showing potential pipelines and mains (see Figure III.2) as an annex to the impact assessment of the proposed CCS Directive (EC 2008b).

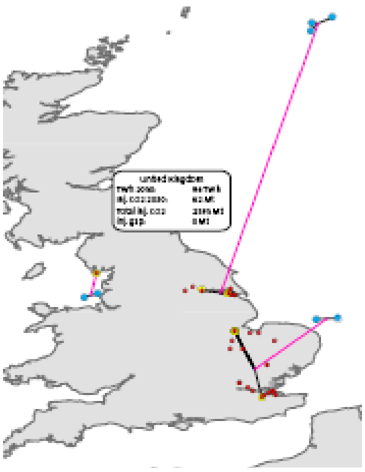

Figure III.2 Suggested UK CO_2 transport network in EC (2008b)

Provided that the volumes of CO_2 to be transported are well understood, least-cost network development will maximise use of hubs and trunks (mains) subject to environmental safety and constraints.[44] The market may fail to provide this long-term least-cost method by delivering undersized pipelines. In network development and

[44] In other sections of the analysis it is shown that fewer, larger pipelines are preferred from an environmental and safety point of view than many small pipelines.

operation, market failure is the key reason for state intervention (OECD 2003). The following basic forms of potential market failure have been identified as part of this project, although more thorough research as part of a dedicated project is recommended for this important issue:

- Due to the fact that actual requirements for the CO_2 volumes to be transported and stored are not understood, an excess of individual pipelines may be developed or hubs and trunks may be undersized. Therefore, the first step towards least-cost network development is an overall CCS policy that is as clear as possible.

- Balancing investment, costs, risks and benefits. Pipeline development requires high initial investments into an asset that has no salvage value. The majority of UK pipelines have been developed under national ownership or through risk-reducing 'take-or-pay' contracts.

In the UK gas supply first developed through competition and private investment in pipelines (this applied to the supplies of town gas – made from coal – for lighting in London as early as 1830–1840) (Oxford Institute for Energy Studies 1999). However, as soon as natural gas was discovered offshore, the network was regarded as a natural monopoly and was assigned for national ownership – and investment. The development of gas networks through national investments applies to most gas networks in Europe. The principles of liberalisation and private ownership of pipelines is applied more successfully in a mature market and to an existing infrastructure basis than it is in a new market; the extreme illustrations of this are the failed electricity system privatisation programmes in developing countries (e.g. India, Nigeria and others). While other factors such as overall economic risks were involved in difficulties in building networks in developing countries, the novelty of CCS can make it difficult to attract private capital for a large-sized efficient network.

Under a nascent CCS system there is the risk that the social benefit from CCS is not translated into specific and secure financial incentives (for example see the discussion on the role of EU ETS above). The state could intervene to address this problem with a number of methods, ranging from 100% state investment and ownership, to public and private partnerships (widely applied by the Department for Transport for example), to risk guarantees (widely applied by the World Bank for the development of networks in non-OECD countries and proposed by the EC for trans-European CCS networks[45]), to grants and guaranteed feed-in tariffs for CCS electricity. This would in turn increase confidence in transport revenues for pipeline operators if separate from power station operators, support per tonne of CO_2 stored etc.

There is concern about electricity sector operators using CCS in order to apply market power and prevent entry or competitive operation (EC 2008a). Abuse of market power can occur in particular as a result of the use of 'take-or-pay' contracts,46 which may be necessary in order to secure the investment in pipelines. Such contracts are very common in the gas markets but are not favoured under current EU energy markets which request third party access to networks. Similar third party access principles are introduced in the proposed CCS Directive – EC (2008a).

In conclusion, government intervention will be required in order to ensure that investments in CCS transport networks are efficient in the long term – bringing maximum social benefits, while being secure and profitable for investors, as well as fair for third party players in the electricity market.

[45] http://ec.europa.eu/energy/climate_actions/doc/2008_co2_comm_en.pdf.
[46] Under such contracts the developer would receive a payment independent of whether the customer uses the booked pipeline capacity or not.

Background on reviewed literature

IEA GHG (2005b) find mixed results concerning the cost reduction potential of using a backbone pipeline system and this depends on which storage options are available. When all storage structures are available, backbones are found to make no significant difference to cost estimates. However, when storage is restricted to offshore storage, using a backbone lowers cost by almost €1 to €7 per tonne for the 26.1 Gt CO_2 being stored.

In the case where storage options are limited to hydrocarbon fields, costs are lower per tonne of CO_2 when using the backbone with an 8% reduction in costs. For transport and storage of 16.3 Gt CO_2, the backbone approach leads to costs of €7.98 per tonne compared with €8.65 per tonne without a backbone, a total cost reduction of €11 billion. The backbone approach also means that more CO_2 can be stored for less than €20 per tonne (20.6 Gt compared with 16.3 Gt without a backbone); however, the additional CO_2 transported and stored leads to relatively high costs. When storage is restricted even further to solely offshore hydrocarbon the backbone approach becomes much more financially attractive and costs are reduced by €2.5 per tonne of CO_2.

In Element Energy et al. (2007) a comparison is made between a 'centrally planned' CCS pipeline network and a 'project by project approach' in the UK and Norway. The two scenarios differ in terms of market and regulatory environment and these differences are highlighted in Table III.1.

Table III.1 Assumptions for different pipeline scenarios (Element Energy et al. 2007)

Considerations/assumptions	Centrally planned network	Project by project approach
Level of government action	High	Low
Main drivers	Maximum cost-effective CO_2 abatement	Enhanced oil revenues
Degree of foresight	High	Low
Assumed oil price	\$50/bbl	\$50–100/bbl
Implicit carbon price	High	Low
Choice of sources	Main priority is highest CO_2 abatement at lowest lifetime cost for the whole network. Diversity encouraged	Sources nearest EOR opportunities favoured
Choice of sinks	Lowest risk and cheapest sinks encouraged. Diversity encouraged.	EOR-only sinks

Under the centrally planned scenario, hubs and mains play a crucial role. Existing offshore infrastructure is re-used wherever possible and this leads to a clustering of onshore sources close to the main pipelines. These are connected by hubs as shown in Figure III.3 for the UK. Clustering sources keeps costs low.

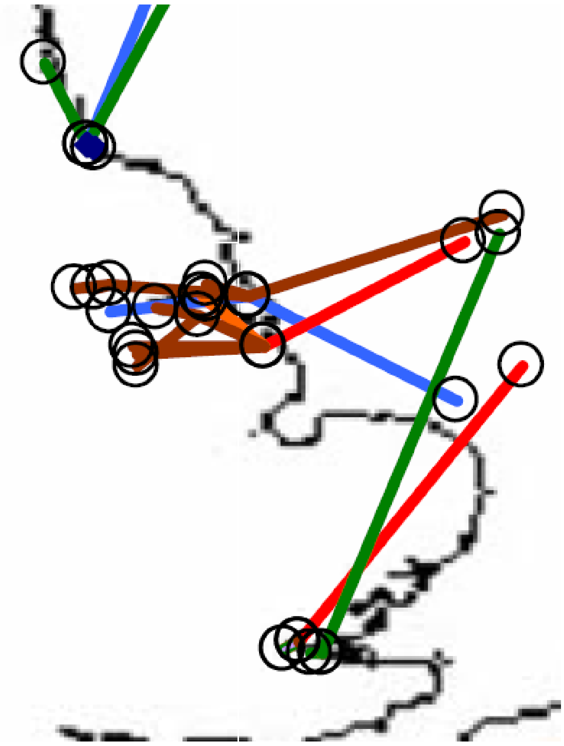

Figure III.3 The use of hubs under a centrally planned scenario in the UK (Element Energy et al. 2007)

In the project by project scenario, 'higher oil prices support a demand for CO_2 for enhanced oil recovery from North Sea oil wells'. As only EOR sinks are utilised under this scenario, the storage options are far more limited. Infrastructure re-use is most likely for storage of CO_2 in depleted gas fields and oil fields without EOR and substantial new infrastructure will be required for CO_2 transport and injection for EOR (Figure III.3).

Table III.2 gives a comparison of the total CO_2 abated as well as the lifetime cost per tonne of CO_2 abated (excluding capture costs) for the two scenarios described above.

Table III.2 Comparison of different pipeline scenarios (Element Energy et al. 2007)

Variable	Units	Centrally planned network	Project by project
Total CO_2 abated	Mt	1,889	836
Total cost[47]	£ million	11,539	15,425
Cost per tonne abated	£/t	6	18

The tendency is that lifetime system cost of carbon improves as connectivity and clustering increases (Element Energy et al. 2007).

[47] A treasury discount rate of 3.5% is used to give total cost and system costs and this figure includes the cost of commercial loans (8% over 20 years).

The CO_2-Infrastructure for EOR in the North Sea (CENS) project (Markussen et al. 2004) proposed a CO_2-pipeline infrastructure model in the North Sea capable of transporting more than 30 million tonnes of CO_2 per year. The CO_2 will initially be captured from onshore coal-fired power plants in the UK and Denmark, and used commercially for EOR in the maturing oil reservoirs in the North Sea.

During a 25-year 'economic' lifetime, the project could produce 2.1 billion barrels of incremental oil obtained while sequestering 680 Mt CO_2 in recognised secure depositories. The total transportation investment cost is estimated to be $1.69 billion with an 'end-of-pipe' cost for delivered CO_2 assumed to be in the range of $32–35 per tonne.

'The main components of the project, as currently envisaged, consist of an onshore pipeline infrastructure in Denmark and the UK combined with two main (24-inch diameter) feeder lines joining a southern hub near Fulmar and Ekofisk. The main 'backbone' is a 30-inch diameter pipe transporting the CO_2 north to the fields in the Tampen area off the West Coast of Norway' (Markussen et al. 2004). The project highlights the economic benefits of hubs and mains as these are included as an integral part of the network design to ensure the lowest cost solution. Figure III.4 gives an overview of the envisaged pipeline infrastructure.

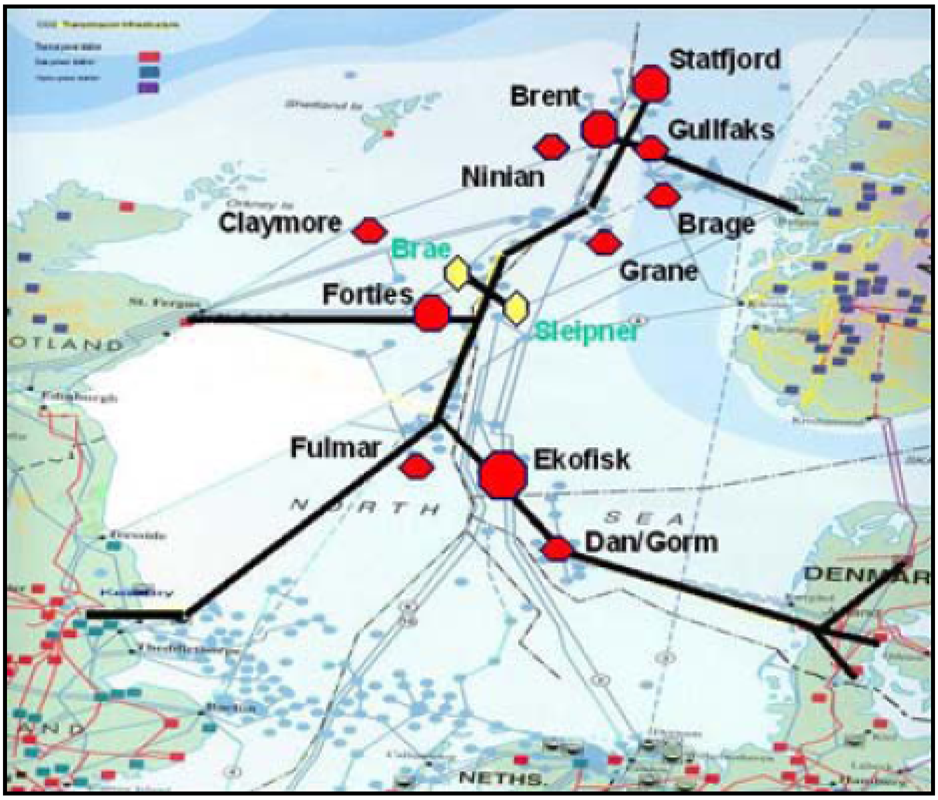

Figure III.4 Overview of possible CO_2 pipeline infrastructure together with a portfolio of mature oil reservoirs that are representative candidates for CO_2 flooding (Markussen et al. 2004)

Whichever scenario is examined for a possible evolution of a CO_2 pipeline infrastructure, a recurring theme is the re-use of the existing pipeline infrastructure. The EEEGR (2006) report concludes that pipelines in general and particularly those in the Southern North Sea (SNS) can be re-used for a number of transportation options. Any future usage must, from an economic and practical viewpoint, take advantage of pipelines in place. The fact that central North Sea trunk lines will be used for oil and gas for many years to come is not a problem for re-use as it makes it more likely that by this time CO_2 capture costs will have dropped and CO_2 credit values will have increased. The study suggests that there are over 200 separate pipelines in the UK continental shelf of a practical size for re-use, with a total length of over 9,000 km.

However, Element Energy et al. (2007) have highlighted some limitations of re-using existing pipeline infrastructure. The main limitation of re-use of existing lines is design pressure, which varies between 90 and 180 bar depending on age and original duty. A new purpose-built CO_2 line, on the other hand, is likely to vary between 200 and 300 bar and utilising the lower pressure existing pipelines will lower the transportation capacity. However, most of the major existing North Sea trunk lines have a relatively large diameter and still offer significant CO_2 capacity. A total of 28 pipelines identified in the UK sector appear to have a capacity in the range 10–50 Mt CO_2/year.

Assumptions in IEA GHG (2005b) report: These costs are based on the investment costs reported above in the previous table. They include operation and maintenance costs for the pipeline (assumed to be 3% of investment costs) as well as operation and maintenance costs for the booster stations (assumed to be 5% of the investment cost), a discount rate of 10% and an operational lifetime of 20 years. The base year is 2000.

Assumptions in Poyry (2007) report: These estimates are based on a specific example, based on a power station located in Aberthaw in Wales and transporting to an aquifer. Costs are classified according to their onshore and offshore components. The onshore component looks at transporting the CO_2 from Aberthaw to Bacton on the east coast of England. This is a distance of 444 km (adjusted for terrain). The estimates include three operational boosters (and three on standby) and assume a pipe diameter of 0.5 metres. The offshore component looks at transporting the CO_2 from Bacton to the aquifer, a distance of 102 km (adjusted for terrain). It assumes a pipe diameter of 0.6 metres. The costs are estimated for 2015. They exclude industrial sites around the power plant (this has the effect of reducing the volume of CO_2 that is transported, therefore affecting the unit cost).

Table III.3 Discount rate assumptions for transport studies

Study	Discount rate assumptions
IEA GHG (2005)	Operational lifetime – 20 years Discount rate – 10%
Markussen et al. (2004)	All net present values (NPVs) used are assuming an 18% discount rate for oil field operators, 15% for the pipeline operators, 12% for power plant owners and 7% for the governments
Element Energy et al. (2007)	The efficiency of the network is measured by its lifetime cost per tonne of CO_2 abated. A treasury discount rate of 3.5% is used to give present value system costs. System costs that account for the cost of commercial loans (8% over 20 years) are also shown
EEEGR (2006)	-
IEA GHG (2006)	IEA GHG standard assessment criteria (for power generation techs) are as follows: 85% load factor 10% discount rate 25 year operating life Sensitivity to a lower (5%) discount rate was also tested
IPCC (2005)	Fixed charge factor (FCF, also known as the capital recovery factor) reflects assumptions about the plant lifetime and the effective interest rate (or discount rate) used to amortise capital costs. In its simplest form, FCF can be calculated from the project lifetime, *n* (years), and annual interest rate, *i* (fraction), by the equation: FCF = i / [1 – (1 + i)–n]. As the IPCC considers a wide range of studies this is different for each and varies roughly between 10 and 15%

Annex IV: The interaction of potential environmental and health risks and CCS economics

While environmental and health impacts of a pipeline/storage network is an area that requires very careful consideration to an extent of detail beyond this study, health and safety considerations affect the economics and other aspects of CCS relevant to CCS readiness. The main focus of this short section is a summary of the health and safety assessments undertaken as part of the Impact Assessment of the CCS Directive – EC (2008b).

The Impact Assessment of the CCS Directive assumes that a 10% concentration of CO_2 in air would lead to 100% fatalities among the exposed population, with a sensitivity run on the 7% concentration that may affect children and elderly. The dispersion modelling assumed a flat terrain, an average population density for each EU Member State and both onshore and offshore storage. The modelling was undertaken assuming a stylised pipeline type running at 100 bar pressure and with a size of 30 inches (76.2 cm).

The results of the modelling suggested that, under the base case of 10% concentration, for some of the scenarios (e.g. mandatory CCS for coal and gas power stations and mandatory retrofit for all fossil-fuel stations by 2020) the risk of asphyxiation would average at five fatalities per year, which contributed to this option being rejected. There is no indication in the Impact Assessment document of the number of fatalities associated with making CCS mandatory for new plants only in 2020.

The assumptions above, such as population density and types of storage, and therefore the assessment of impacts of options, are an exaggeration of the likely impact. In reality it is likely that pipelines would be routed away from densely populated areas, which would reduce the potential fatality risk. In the UK, offshore storage is expected to dominate, which would also reduce fatality risks.

The EC (2008b) analysis suggests that at a certain network size the risk to the population can become unacceptable under certain criteria. It is likely that the network sizes currently envisaged for CCS do not reach critical levels (e.g. the natural gas pipeline network of Europe was assessed at 110,000 km compared to 30,000 km under the maximum pipeline deployment scenario considered as part of the impact assessment). The other consideration is the speed of policy development and implementation in what is a relatively new area in Europe. Given the novelty of supercritical CO_2 transport for most European and UK regulatory bodies, it is important that health and safety aspects are given appropriate consideration. The proposed demonstration projects are likely to support this consideration.

Annex V: Questions raised by the Environment Agency to guide the study

An initial literature review was undertaken to assess the following:

1. How far technically can an operator go to be carbon capture ready?
2. What is the Environment Agency's legal position in terms of requiring operators to be carbon capture ready?
3. What is the business case for an operator to be carbon capture ready? Will they do it themselves or does the Environment Agency have a case to require them to do it?
4. Should the regulator refuse a licence for an operator if they haven't purchased a storage site for the CO_2 – is this a reasonable approach?
5. What are the key factors in actual CCS deployment? / When would a power station be built with CCS (not just CCS ready)? / Will CCS readiness (CCR) turn into CCS at the same date as when new built plants will include CCS?
6. Who/what controls these factors?
7. What would be the regulatory framework that would promote CCS as compared to CCR? / Is it credible that the EU ETS will deliver CCS? / Is CCS more likely to happen through regulation (enforced behaviour) or will operators judge it is in their interest at some point?
8. Is there anything the Environment Agency can do to promote CCS, as compared to CCR?
9. What is the current position with regards to onshore storage in the UK?

An interim paper was issued to the Environment Agency in January 2008 and a workshop with key staff was held on 6 February 2008. Following feedback from the staff involved in the workshop, additional analysis questions were identified, including:

1. What factors should the Environment Agency consider in judging the feasibility of proposed transport routes to storage?
2. Under what conditions should the Environment Agency challenge proposed transport routes and storage sites?
3. Is there a role for the Government and regulatory bodies in securing the proposed routes once they have been agreed?
4. If they don't undertake such a role, will this undermine the 'capture readiness' of new plant?
5. Are there planning issues related to a pipeline/storage network? Is central planning a 'must do' for CO_2 transport? How is the Planning White Paper/Marine Bill be relevant to this discussion? What changes should the Environment Agency seek, if any?
6. What is the evidence that hubs and 'mains' would benefit the economics of CO_2 transport?

7. What scenarios have been developed for how a pipeline network would evolve?
8. What are the potential financial (e.g. risk distribution)/regulatory barriers to the development of infrastructure that is least-cost/unit CO_2 transported?
9. Is regulatory/government intervention believed to be necessary for the development of the least-cost infrastructure?
10. What are the potential environmental/health impacts of a pipeline/storage network? Would this affect the conclusions of any of the above?

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